

## **EVALUATION METHODS IN COMPETITIVE BIDDING FOR ELECTRIC POWER**

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## EXECUTIVE SUMMARY

### Background

Competitive bidding for new electricity generation is a rapidly growing phenomenon. A number of utilities have completed auctions for long-term power contracts with private suppliers, and more are being proposed. Yet despite all of this activity, there has not been any systematic analysis of the design choices posed by this process. Are these procedures economic? What biases are built into the process? How are various objectives traded off against one another in the implementation of competitive bidding?

In this report we undertake a systematic analysis of some of the competitive bidding procedures that have been used or are being proposed at the state level. We take no position on the larger political debate surrounding this process. These policy issues, raised principally by initiatives of the Federal Energy Regulatory Commission (FERC), address the scope and appropriateness of competitive bidding. The FERC Notices of Proposed Rulemaking argued that competitive bidding should not only be allowed for Qualifying Facilities (QFs) under PURPA, but should also be expanded to include a new class of private producers called Independent Power Producers (IPPs). Various interests have argued this proposition. Some have endorsed it; some have opposed it; and some have suggested that bidding is fine for QFs, but should not include IPPs. Regardless of how these questions are ultimately settled, however, the current reality is that competitive bidding in several forms is currently being undertaken. To understand this phenomenon in practice, it is useful to analyze it systematically in detail.

Constructing a competitive bidding procedure requires accounting for complex pricing, performance and contractual issues. Utility planners have experience analyzing the multi-attribute nature of power projects, but the bidding environment adds a new dimension. With bidding, the attributes must be unbundled, valued explicitly and independently, and traded-off in arms-length transactions. As utilities experiment with making these evaluations, it is inevitable that approximations will be used that affect technologies and bidders differently.

We find that the bidding systems in use or under advanced stages of review differ substantially from one another. The most fundamental distinction involves the approaches taken by utilities to scoring and ranking projects. At one extreme, some utilities have adopted linear self-scoring point systems. These systems provide bidders with explicit evaluation sheets where each relevant feature receives a specified number of points depending on the project characteristics. Bidders add up their own scores and the utility verifies the data and selects winners based on the highest scores. In contrast, other utilities only reveal bid evaluation criteria in general terms. In these systems the rank of any bid cannot be verified after the fact, and the utility possesses information about the evaluation process that bidders do not. We call the first approach an "open" system and the second approach "closed". Open systems emphasize the perception of fairness in the evaluation; closed systems emphasize flexibility for the utility.

Bidding systems also differ in the "nominal" weights assigned to price and other factors; these weights are provided by the utility in its solicitation. For example, dispatchability, the

ability to follow load fluctuations, is virtually required by Virginia Power, but only given moderate weight by most other systems. Utilities have also adopted various approaches to bidders that require front-loaded payments. The term "front-loading" refers to a payment stream that is above estimated avoided cost in the short run and below it in the long run. While bidders often require front-loading to meet financing constraints, utilities sometimes feel that it imposes a risk on ratepayers because the promised long-run benefits may never appear. Boston Edison's proposed second solicitation imposes very heavy penalties on front-loaded bids, while Virginia Power allows this practice to some degree for the capacity payment. Finally, there are significant differences among the bidding systems regarding the size of auctions. For example, the 1988 Virginia Power solicitation requested 1750 MW, while the minimum capacity need requested by a utility was 50 MW.

## **Key Findings**

### **Nominal vs. Real Weights**

The study demonstrates that the nominal weights attached to project features in the linear self-scoring systems do not necessarily determine the outcome of auctions. The real weight of a given feature, that is, how much the weighted feature actually influences the outcome of the bidding, depends on the distribution of bids on all features. If all bidders offer the same quality in one respect, then that feature will have no effect on determining winners. In such a case irrespective of the nominal weight of such a feature, its real weight is zero. Conversely, if a feature elicits wide variation among the bidders, then its real weight is greater than its nominal weight. We show in a particular case that two systems that nominally place very different weights on price (50% for Orange and Rockland Utilities vs. 70% for Niagara Mohawk Power) end up ranking bids in nearly the same order as a price-only system.

### **Front Loading**

Front loading is a contentious problem for regulators, utilities and non-utility generators. Under traditional rate base treatment, new utility plants can cause "rate shock" because capital charges exceed fuel savings in the early years of operation. These effects diminish as the plant is depreciated. Non-utility generators often seek level capital cost recovery in their power contracts. This can still lead to costs in excess of operating economies, although not to the same extent as with the traditional treatment of depreciating rate base.

We argue in several ways that front-loading penalties that have been proposed by some utilities in their bidding systems are excessive. The practical impact of excessive penalties for front-loading is to discriminate against capital-intensive technologies, such as biomass, clean coal technologies, hydro, solar, etc. We constructed an economic model of front-loading called the "implicit loan method," which was used to compute the interest rate implied by two proposed bid evaluation systems. The concept of the "implicit loan method" is that payments above avoided cost in the near term should carry an interest rate reflecting the risk that a plant will not

be operating in the future when payments are below avoided costs. In effect, customers would be getting repaid in later years for their "loan" in the early years of operation. Projects with relatively low risks might require interest rates that are slightly above typical utility bond rates to reflect the limited operating history of QFs and IPPs. Riskier projects might require interest rates over 15%. For instance, the last public offering of debt made by Public Service of New Hampshire before its bankruptcy required a 17-1/2% coupon in the spring of 1987. We found that for a particular representative project evaluated in the Boston Edison framework, the implicit loan interest rate ranged from 25-65%, depending on the security offered. This is unrealistic in light of risk premia required on other loans. We also tested this same project using the proposed Niagara Mohawk Power evaluation system and found that the implicit interest rate ranges from 13-16%, which is more reasonable.

### **Simulating Dispatchability**

We simulated the auction conducted by Virginia Power in 1988. This competition virtually required dispatchability by bidders, and evaluated bids in a "closed" system. A priori, linear self-scoring is economically inefficient in this situation, because it is impossible to specify in advance the value of different degrees of dispatchability. In this type of large-scale auction, the value of one bid depends upon all of the other bids. In this case the interdependence is greater than the simple distinction between nominal and real linear weights. The amount that any project could be expected to operate depends on the cost characteristics of all competitors. In small-scale auctions, where interactions are potentially negligible, linear self-scoring can be acceptable. However, the interactions among projects are of fundamental importance in situations in which large resource additions are being evaluated (i.e., where more than 10% of the system is being acquired in one solicitation). We structured our simulation as an optimization using the EGEAS model to select from an artificially constructed distribution of bids. We then examined various ways that the utility's announced preference for coal-fired power projects could be incorporated in this framework. Even though optimization does not yield a simple ranking of project economics, we found that it was just as amenable to accounting for non-price factors as the linear self-scoring systems.

### **Open vs. Closed Systems**

Achieving the desirable efficiency properties of the Virginia Power type approach requires a "closed" evaluation system. A complex computer program is required, which must be used with a lot of data and imagination. However, at the present time, the "open" systems represent the dominant trend in the design of evaluation systems. One reason for the prevalence of "open" self-scoring is the underlying background of distrust between utilities, private suppliers and state regulatory agencies. This distrust goes back to the history of PURPA implementation and the planning problems experienced by utilities during the last 15 years. "Open" systems lay out all value judgments explicitly so that there can be no claim of hidden bias or prejudice in the actual scoring. The process is automatic and auditable. In a "closed" system, the utility regulator is implicitly granting substantial discretion to the utility, and keeping information from the bidders.

These arrangements require trust in the notion that the utility will act fairly and end up with an efficient (i.e., least cost) set of choices.

### **Project Viability**

The issue of project viability is one area that repeatedly emerges as a trouble spot from our analysis of bidding systems. The basic problem involves the need for utilities to have some assurance that the offers made by bidders are legitimate and that projects will operate over the long term if accepted. However, the state of the art in assessing project viability is not advanced. Many evaluation systems incorporate unrealistic wish lists that mix relatively trivial minimum threshold criteria with nearly impossible expectations. At times the viability criteria even contradict other preferences expressed in the bid evaluation systems. For example, the desire for financial viability on the part of bidders may require them to front load prices. If front-loading is then penalized, how can a bidder adequately cover debt? Other areas of concern associated with viability include the need to obtain environmental permits for siting and securing adequate long run arrangements for project maintenance.

It is in the interest of consumers, utilities, regulators and private suppliers to develop bidding systems that are efficient, workable and fair. To achieve these objectives it will be necessary to experiment with and analyze new ideas to determine how much information and risk sharing is appropriate. This task is important because the evolution of electric power markets may increasingly be determined by bidding procedures and contractual arrangements. The cost of failure could be a major regulatory crisis in the power sector, which all parties can ill afford.

## 1. INTRODUCTION

Competitive bidding for new electric generation by private power producers is becoming an increasingly important feature of utility resource planning and represents a major departure from the historical practices of the electric utility industry in which new generating resources were constructed by vertically-integrated utilities. Bidding in the electric supply context originated as a reform of the PURPA process for purchasing power from certain private producers. Some states and utilities have designed their bidding systems to allow all potential suppliers to compete, including Independent Power Producers, a class of potential suppliers that are privately-owned but do not meet the tests for qualifying status under PURPA, and even firms that offer demand-side reductions. Competitive power procurements promise to fundamentally reshape the market for power technologies.

In this study, we examine the bidding processes being used or proposed by utilities to evaluate bids made by producers. The design of bid evaluation systems is a challenging task because it requires an explicit externalization of many aspects of utility planning as well as treatment of the issues associated with long-term contracting. For example, contracting for new generating capacity requires utilities to unbundle various attributes of power projects that have not been priced in the market previously (e.g., operating characteristics, project viability, and price risks). This is a formidable and qualitatively new problem for utility planners. Moreover, the practical demands imposed by the need to have systems that are workable and reasonably simple means that short-cuts, approximations, and rules of thumb will be developed. In some cases, this can lead to unintended biases in bidding systems. In this study, we focus our analysis on those non-price factors that particularly affect the prospects for capital-intensive technologies.

In Chapter 2, we review the origins of competitive bidding and discuss three background questions: (1) what is the nature of competitive bidding for new electricity capacity? (2) why has bidding appeared and why should we study it, and (3) where is bidding being practiced? In Chapter 3, we describe current and proposed bid evaluation systems and introduce the basic conceptual approaches that have emerged to date. Chapter 4 focuses on several theoretical issues that arise in bid evaluation: the treatment and pricing of various types of risk and the determination of the economic value of non-price factors. Evaluation of the non-price factors of proposed projects is complex and unprecedented. We discuss the treatment and allocation of risks involved in project failure and fuel price uncertainty. We also develop an economic framework that can be used to evaluate front-loaded bids, which has proven to be a key issue for private developers, utilities and ratepayers. In Chapter 5, we discuss methods for evaluating the value of dispatchable power. Dispatchability is one of the most important operational features that private suppliers can provide to electric utilities. We analyze how Pacific Gas & Electric and Virginia Power have incorporated dispatchability into their proposed bid evaluation systems. Virginia Power's approach is unique and less transparent to bidders, thus we conduct a simulation of their existing system and recent large-scale procurement. In Chapter 6, we attempt to contrast the various approaches used by utilities by evaluating them against a standard set of hypothetical bids from eight generic projects. This exercise illustrates the importance of

different evaluation approaches in determining the ranking of bids. Finally, Chapter 7 summarizes our key findings, assesses the state of the art in competitive bidding systems for electric power, and outlines future research needs.

## **2. THE ORIGINS OF COMPETITIVE BIDDING AND THE PROSPECTS FOR CAPITAL-INTENSIVE TECHNOLOGIES**

In this chapter, we briefly summarize the recent history of the U.S. electric utility industry and discuss reasons why state public utility commissions (PUCs) and utilities are establishing bidding systems to procure new generation resources. Readers that are familiar with this background will find it more productive to proceed to Section 2.3 where we describe the challenges that bidding systems pose for utility planners and identify key design issues that affect capital-intensive technologies.

### **2.1 Historical Overview of the Electric Utility Industry**

For most of its history, the electric utility industry has consisted primarily of vertically integrated firms that built central station power plants and bulk power transmission to realize scale economies in generation and transmission. The utility retained ultimate financial and managerial responsibility, although these construction projects were contracted, in whole or in part, to private engineering firms. The utility's financial earnings were determined to a great extent by the successful development of its generation projects. The basic regulatory mechanism that governed the industry was an obligation to serve on the part of the utility, and the recovery of investment costs through rate adjustments administered by a public utility commission.

The relative influence and contribution of private unregulated firms in the U.S. power industry has changed quite dramatically over time. Prior to the 1920s, almost half of total U.S. generating capacity was located at industrial sites (OTA, 1983). Figure 2-1 illustrates the dramatic decline in the relative contribution of private production that occurred after the industry became regulated. The dominant reason for the historic decline was the increasing efficiency of central station production. Electric prices declined in real terms from 1940 until about 1970. This price situation changed during the 1970s as the utility industry was beset by dramatic increases in fuel costs as well as increasingly stringent environmental regulation (e.g., Clean Air Act of 1970 and its 1977 Amendments). The oil price shocks increased already high levels of inflation, which resulted in higher construction and financing costs for power plants (DOE, 1983). The overall effect of these developments resulted in increased electric prices (in real terms) and demand growth slowed dramatically.

PURPA was passed during this tumultuous period and fundamentally altered the market position of private production. PURPA required that utilities purchase electricity from a class of producers designated as Qualifying Facilities (QFs) under pricing arrangements governed by a concept known as the utility's "avoided cost." State regulators were delegated the responsibility for implementing the avoided cost principle. The federal government conferred QF status on applicants that met certain cogeneration efficiency tests or used renewable energy for projects less than 80 MW. QF status exempted the supplier from public utility regulation.

PURPA has been extremely successful in stimulating cogeneration and small power production. During the 1980s, about 13,000-15,000 MW of non-utility capacity were built, although there were significant regional variations in non-utility capacity additions (Griggs, 1988). There was an enormous outpouring of private production in states that had a favorable regulatory climate as well as significant potential for cogeneration. For example, it is estimated that QFs will represent about 15-20% of the total generation of California's two largest utilities

## Historical Trends in Electric Generating Capacity

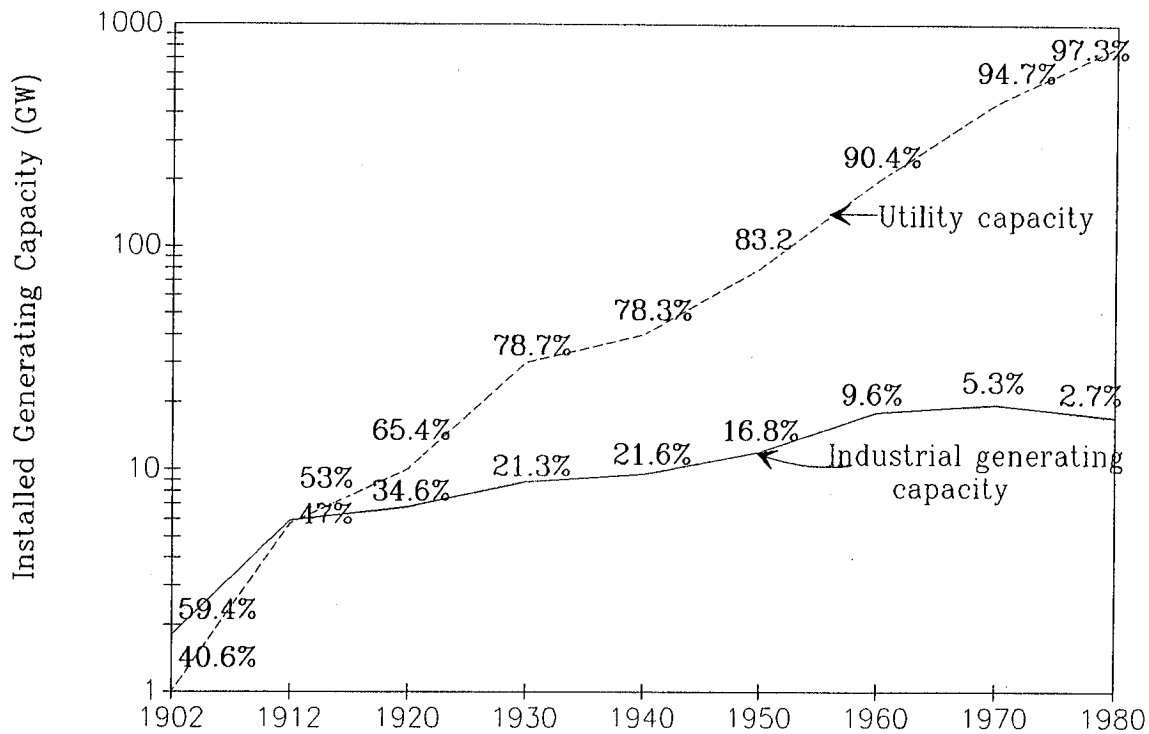


Figure 2-1 shows that utility-owned generating capacity has dramatically increased its relative share of total U.S. installed generating capacity since 1915.

Source: Office of Technology Assessment, "Industrial and Commercial Cogeneration," February 1983.

by the early 1990s. Significant levels of QF development also occurred in Texas, New Jersey and Maine. In contrast, some regions with low avoided costs had little QF development.

PURPA was not an unqualified success, as difficult implementation problems arose, particularly in those states with significant levels of QF development. In response, a few utilities and PUCs began experimenting with the use of competitive bidding procedures to ration the supply of private power development and to select the most beneficial projects. PURPA never explicitly envisioned an auction-like process for allocating new capacity contracts among potential suppliers.<sup>1</sup> However, PURPA did not explicitly forbid bidding. Substantive legal arguments have been raised on the issue of whether bidding is a legitimate implementation strategy under PURPA (Griggs, 1988). Some PUCs have forged ahead, while others were unwilling to undertake bidding experiments because of these ambiguities.

In March 1988, the Federal Energy Regulatory Commission as part of its review of PURPA issued three Notices of Proposed Rulemaking (NOPRs): administrative determination of full avoided costs (ADFAC), regulations governing competitive bidding programs, and regulations governing independent power producers (FERC, 1988a,b,c). The FERC NOPRs actually broadened the areas of debate by including utilities as potential participants in bidding as well as a new class of private producers. Independent Power Producers (IPPs) are private suppliers that do not meet the tests for QF status.<sup>2</sup> Under FERC's proposal, IPPs would be subject to only minimal regulation. FERC also proposed that states be allowed to implement "all-sources bidding" in which IPPs would be included as well as QFs. At the current time, FERC has not issued final rules on any of the three rulemakings; FERC's recommendations on IPPs were particularly controversial.

While FERC deliberates these issues, an increasing number of states and utilities continue to propose and implement bidding systems for new generating capacity. Table 2-1 summarizes current experience of utilities with electric power auctions, and includes data on the amount of capacity solicited by utilities as well as response by suppliers, as indicated by the amount of capacity offered. Initial experience with power auctions suggests that there is a large pool of private suppliers willing to provide capacity at current avoided costs. Thus far, the capacity offered by private producers has often been 10-20 times greater than the utility's capacity requirements. In addition, a number of utilities, most of which are implementing PUC orders in New York and New Jersey, have recently proposed bidding systems and plan to hold auctions during the next several years (Table 2-2). Many of these utilities are proposing an integrated auction in which both supply and demands resources compete to fill the defined resource need.

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<sup>1</sup> Note that under PURPA both winning and losing bidders may still sell power to the utility. Winning bidders receive both the capacity and energy components of the utility's avoided costs, while losing bidders may receive only the energy component of the utility's avoided cost.

<sup>2</sup> IPPs are defined as entities that are selling from facilities that are not regulated on a cost-of-service basis, that do not control transmission facilities essential to the buyer, and, if they are a franchised utility, are selling to buyers outside their retail service territory.

**Table 2-1. Competitive bidding for resources by electric utilities.**

Utility	Date of RFP	Capacity Requested (MW)	Capacity Offered by Bidders (MW)	Number of Bids	Features
Central Maine Power	6/87	100	1444	51	QFs only
Central Maine Power	12/87	100	907		Power & Conservation
Boston Edison	10/86	200	1850		QF Only
Boston Edison	4/89	200			QF Only
W. Massachusetts Elec.	2/88	54			
Virginia Power	3/88	1750	14653	96	IPPs and QFs
Virginia Power	12/88	300			Peaking Power
Green Mountain Power	7/88	114	1700	34	Separate DSM
Central Vermont	6/88	50	658		All-source
New England Power	7/88	200	4700		
Sierra Pacific	5/88	125	2800	94	"Open" RFP
Seminole Electric	5/88	440	2000	8	
Delmarva Power	10/88	200			
SMUD	9/87	400	6479	49	

**Table 2-2. Proposed electric power auctions.**

Utility	Date of RFP	Capacity Requested (MW)	Features
Long Island Lighting	1989	300	All Supply sources
Orange & Rockland	1989	100	Integrated Supply/DSM
Consolidated Edison	1989	200	Bids by 1993; Integrated Supply/DSM
Niagara Mohawk	1989	350	Integrated Supply/DSM
New York State Electric & Gas	1989	130	Supply (100 MW); DSM (30 MW) by 1994
PSE&G	1989	200	
Jersey Central P&L	1989	180	
Public Service Colorado	1989		Purchases from QFs up to 20% of total system firm peak load
Oglethorpe Power	Pending		
SDG&E	Pending	100	
Puget Power	1989	100	Integrated Supply/DSM
Hawaii Electric	1989	500	Geothermal energy
Central Maine Power	5/89	150-300 ~700	By mid-1990s; All-source By 2000; All-source

## 2.2 Why Are PUCs Establishing Competitive Bidding Systems for Electric Power?

Recounting the events leading up to the appearance of competitive bidding does not explain why it has occurred. We would argue that the popularity of competitive bidding is strongly linked to the failures of central station power plant construction in the last ten years as well as problems associated with implementing PURPA. The changes in the business environment of the classic integrated utility firm produced many cases of high-cost power plants that came into service during a period of excess capacity. Some of the most notable examples involved nuclear plants that experienced licensing problems, cost overruns, and substantial delays. In some cases these projects were cancelled at substantial cost. In other cases, delays kept such projects out of operation even where there was substantial demand. The response of state regulators was to disallow and/or defer cost recovery. The financial health of the affected utilities was seriously impaired as dividends were reduced and stock prices fell; one utility has filed for bankruptcy.

Utility management has become averse to risky generation construction as a result of the perception that regulation has become hostile. In such an environment, utility's are inclined to minimize investment. Thus, risk avoidance is expressed increasingly by utility executives as an "anti-capital" bias. For example, FERC, in its analysis supporting the NOPRs, argued that currently there is an imbalance between risks and rewards for the utility industry, which means that utilities have strong incentives to minimize their capital expenditures (FERC, 1988d). These views are also expressed in the popular utility trade press as well as in recent academic literature, and run counter to the more conventional view that the classic integrated utility firm over-invested in capital-intensive technology, the so-called "Averch-Johnson" effect (Chao et al, 1984; Newberg and Gilbert, 1988). In the 1960s, when the theory of utility over-investment was first articulated, profitability conditions were favorable to capital-intensity. With the economic changes in the 1970s and 1980s, this was no longer true. Thus, the perception of regulatory hostility to traditional central station power plant construction has made private power production an attractive alternative because the risks of construction cost overruns, licensing delays, and financing problems are transferred from the utility to the private supplier.

In addition, the avoided cost framework of PURPA proved to be a fairly blunt instrument when it came to the subtleties of long-range power system planning. Avoided cost is a "posted price" system under which the utility is obliged to purchase from any and all suppliers. Those states which sought to encourage QF suppliers established long-term contracts based on forecasts of avoided costs. Long-term contracts greatly facilitate private production by reducing financing uncertainties. In California, where such contracts were standardized with few options for the purchaser to tailor terms to their needs, the greatest supplier response was forthcoming.

The California utilities have argued that the magnitude of the supplier response created major planning and operational problems. The open-ended nature of these QF contracts introduced substantial uncertainty about how much power would ultimately be developed. The operating characteristics of the QF projects became increasingly ill-matched to power system requirements. The obligation to purchase provision of PURPA and lack of sufficient time-differentiation in purchase price meant that QF output did not need to follow system load variations. This created a problem during minimum load periods when inexpensive energy resources had to be curtailed in favor of higher cost QF contractual obligations.

Given the operating and planning problems associated with large-scale uncontrolled QF development, competitive bidding appears to be a more efficient way to encourage private electricity supply that is better matched to power system requirements. The financial requirements of suppliers are still met because winning bidders receive long-term contracts that enable them to secure debt. However, projects are differentiated by pricing terms, operating characteristics, and non-price factors that affect project viability. The utility and its PUC must agree on the delineation of the characteristics that distinguish projects, and determine their relative value. While this task sounds reasonable in principle, its implementation presents some formidable problems. We identify these problems in discussing our second threshold question: why study bidding systems?

### **2.3 Why Study Competitive Bidding Systems?**

The realities of competitive bidding require that utilities measure the complex attributes of power projects, although the state of the art is relatively undeveloped. A useful way to think of competitive bidding is in terms of bundled versus unbundled commodities. Simple auctions involve the sale of simple commodities or homogeneous objects: red wheat, Treasury bills, or barrels of West Texas intermediate crude oil. The range of product specifications in each case is narrow. In addition, the entire transaction is typically completed over a short time interval and buyers and sellers often do not have an on-going, long-term relationship regarding that transaction. At the opposite extreme, competitive bidding for the procurement of new weapons systems by the Department of Defense represents a highly complex transaction. In this case, product specification is not known with certainty at the outset; buyer and seller negotiate over terms and conditions for years and different bidders do not offer identical products. Electric power projects are probably closer to weapons systems than to wheat, bonds, or oil along the continuum from simplicity to complexity of transaction. Electric power projects are multi-attribute commodities. Development of electric power may not involve the technical innovation and complexity of modern weapons systems, but it is not a simple and homogeneous commodity. Long-term relations between buyer and seller are an inherent characteristic of these power contracts, in large part because both parties, not just the buyer, are investing capital that is specific to the transaction (e.g., the utility may have to invest in transmission facilities).

The most significant problem regarding the multi-attribute nature of power projects is that these features have never been unbundled and priced in the marketplace. By comparison, the traditional planning process of the integrated utility firm was relatively simple and decentralized. Coordination of the planning activities for fuel supply, generation siting and permitting, construction, and transmission and operation were all achieved administratively within the firm. There was no global optimization over all features to arrive at the ideal project. Typically, rules of thumb were used to identify potential projects and to decide among them (Jeynes, 1968).

In principle, competitive bidding could achieve optimal capacity expansion of the power system if all project attributes could be appropriately valued. Many utilities have attempted to broaden dramatically the range of attributes that are explicitly considered in their bid evaluation systems. However, even for relatively traditional aspects of power system planning, explicit valuation is a new phenomenon. For example, in California, the utilities have argued that excess QF capacity creates minimum load problems and increases utility operating costs. Thus, QF

projects that were more under the control of the utility dispatcher (i.e., "dispatchable" power) would lower costs to the utility compared to projects with contracts that require the utilities to purchase all power (i.e., "must take"). Dispatchability or the ability to follow fluctuations in utility system loads is valuable to the utility. However, even the more sophisticated methods of traditional utility planning do not yield explicit measures of this value. The value of load following is implicitly incorporated in the production simulation/system optimization studies conducted by generation planners. The outcome of such studies would be a recommendation about favored projects, but not a menu of values attached to particular degrees of dispatchability. Such "intermediate" results had no value for planning within the firm, but they are now essential to comparing bids that are differentiated along this dimension.

Although resource planners have not explicitly unbundled the long-range value of dispatchability, utility operators have confronted similar problems in the short run. Many wholesale transactions occur between utilities that are differentiated by delivery characteristics. The premium associated with different degrees of dispatchability can be estimated from market transactions. For example, Bonneville Power Administration has made transactions that are differentiated by degrees of buyer control. Similarly, power pools also differentiate service to members. Nonetheless, this information is short-term in nature and is not immediately transferrable to the long-term planning context. To evaluate long-term contracts, there must be estimates of long-run value and utilities must develop these estimates analytically in the absence of market data.

The analytic problems associated with valuing benefits are even more difficult for "non-traditional" attributes. For example, project viability is a particularly difficult issue. Developing a power project either under regulation or as a private supplier is a complex and uncertain task. The problems include both financing and permitting. The failures of central station construction during the last ten years involved both issues. These problems are not any easier for the private developer. Bid evaluation systems typically include measures of project viability, because an ideal project is worthless if it never materializes. Despite the desirability of measuring the likelihood of success, there is little evidence that current methods discriminate reliably among projects.

In summary, bidding systems need to be studied because of the analytic challenges involved in measuring and unbundling the complex attributes of power projects. Moreover, the practical demands of workability impose limits on the complexity of bid evaluation systems. It is inevitable that approximations, short-cuts, and rules of thumb will be developed to create tractable systems. As we analyze the methods being used or proposed to measure various non-price factors, it will become clear that bid evaluation systems can have substantial biases, intended or not, which affect the prospects for capital-intensive technologies.

## **2.4 What Aspects of Competitive Bidding Influence Capital Intensive Technologies?**

The experiences that led to the relative decline of regulated central station power plant construction are likely to influence the environment in which competitive bidding is adopted and implemented. We characterize this environment as risk-averse. In particular, what is being avoided is uncertainty in the short-run; longer-run risks may actually increase by excessive concern with eliminating short-run risks. Nonetheless, in the current environment, by transferring

the responsibility for power plant financing and construction to private developers, the utility avoids responsibility for the uncertainties associated with these activities. However, the underlying need to provide some stability for private supplier investment remains, and must be balanced against the desire to limit the risks to buyers. Bid evaluation systems incorporate, with varying degrees of explicitness, the trade-off between risk aversion on the buyer's side and accommodation to the supplier. If the utility were willing to underwrite all the supplier's risk, it would offer long-term contracts with take-or-pay provisions. The experience in the natural gas industry with take-or-pay contracts has been so unfortunate, that regulatory agencies are extremely unlikely to repeat it willingly. Ultimately, the terms offered suppliers under competitive bidding will reflect the joint preferences of both the utility and the regulatory agency.

We identify two key aspects of competitive bidding that affect capital-intensive technologies, given this risk averse environment: 1) the utility's desire to assure diversity and reliability of fuel supplies, and 2) efforts by utilities and/or regulators to minimize risks to ratepayers by either forbidding or sharply limiting "front-loading" of payments to suppliers. Fuel diversity is a non-price feature that is very difficult to quantify but one that explicitly favors capital-intensive technologies. Utilities that value fuel diversity often are dependent on oil- and gas-fired generation. Thus, these utilities give a credit in their bidding systems to technologies that promote fuel diversity in the utility's production. These technologies typically use solid fuels or renewable energy and are generally more capital intensive than oil- and gas-fired generation. Projects that use solid fuels or renewable energy thus offer fuel diversity benefits to the utility.

In contrast, projects that rely on more capital-intensive technologies are adversely affected by stringent limits on "front-loading" of bid payments. Utilities typically project a rising trajectory of avoided costs against which bidders must compete. In looking at the issue of "front-loaded" bids, it is useful to consider the problem of contract terms from the point of view of the supplier. The two most fundamental constraints on project development are economics and finance. The economic feasibility of a power project is a threshold requirement that is often assessed on a life cycle basis. The basic question is, do long run revenues cover all costs? Typically, the financial constraint is more binding. The project must attract debt financing. Revenues must be sufficient to cover operating expenses, interest and amortization, and provide returns on equity from the start of operation. Often, the debt maturity is considerably shorter than the economic life of the project. This puts a burden on returns in the early years of operation, particularly if revenues are expected to increase over time. Thus, the financial feasibility of a project is often determined by the balance between revenues and costs in the first two or three years of projected operation.

In a world of perfect capital markets, projects would not be limited by financing. Extra borrowing, deferred repayment, long debt maturities or any number of other options could balance revenues against costs on a life cycle basis. However, developers have fewer options in existing capital markets, because debt terms are exogenous and equity investors require a competitive rate of return. To achieve high returns on equity, project developers have an incentive to use the maximum feasible degree of debt. The maximum is determined by the limits on revenue, especially in the early years of a rising revenue stream. Therefore, all other things being equal, projects with lower capital requirements will produce higher returns to investors. This phenomenon is simply a result of their ability to support a greater fraction of debt.

The contract terms offered by utilities in their competitive bidding systems can affect these constraints. "Front-loading" is one approach that is used to ease the barriers to capital-intensive projects and involves pricing above avoided cost in the short run, in exchange for lower prices in the long run. We discuss this issue in some detail in the next two chapters. Bidding systems that forbid this practice, in the interest of avoiding risk to ratepayers, in effect, create a de facto bias in favor of low capital cost technologies. Not surprisingly, utilities have not adopted a uniform approach on the issue of front-loaded bids. In all cases, the supplier's financing need are considered and traded off against the risk perceptions of utilities and their regulators, although this balancing process is seldom made explicit.

### **3. COMPARISON OF BID EVALUATION SYSTEMS: TREATMENT OF NON-PRICE FACTORS**

#### **3.1 Overview**

Determining the economic value of non-price factors is probably the most difficult problem that utilities confront in designing competitive bidding systems for long-term power contracts. Implicitly or explicitly, a bid evaluation system must take the price and non-price attributes of an offer and reduce them to a common measure, a score by which the decision to accept or reject is made. In this chapter, we examine the range of techniques that have been proposed or applied to this problem. Our approach is primarily descriptive and comparative rather than normative (normative questions are discussed in Chapters 4 and 5).

We compare the bid evaluation systems adopted or proposed by four utilities: Virginia Power (VP, 1988), Boston Edison (BECo, 1988a), Niagara Mohawk Power Company (NMPC, 1988a), and Orange and Rockland Utilities (ORU, 1988). We chose these companies because their bidding systems are similar enough to allow comparison, but also sufficiently different so that contrasts are informative. These utilities encompass a range of operating characteristics, economic environments and regulatory regimes; all of which influence their design choices. These four systems all share one fundamental design characteristic: the use of weights to trade off one feature against another. We also describe two other proposed bidding systems that are quite different conceptually: the scheme adopted by the California Public Utilities Commission (CPUC) and Consolidated Edison Company's (Con Ed) proposal for an integrated supply- and demand-side competition. The CPUC proposes a radically different framework, which is based primarily on a system of prescribed constraints rather than multi-attribute weights (CPUC, 1986, 1987, 1988). Con Ed's bidding system is unique because it does not assign an explicit weighting to non-price features initially (Con Ed, 1988).

#### **3.2 Bidding Systems of Four Utilities**

In March 1988, Virginia Power (VP) issued a Request for Proposals (RFP) that solicited bids from Qualified Facilities and independent power producers for 1750 MW of capacity to be delivered by 1994. VP's installed capacity in 1988 was approximately 12,000 MW and the utility purchased about 1500 MW under contract. VP projects that its peak loads will grow at a rate of 3% per year through 1994 to 13,613 MW from current levels (11,300 MW). Virginia Power's RFP thus represents about a 15% expansion of its system, which is a large increment by any definition.

The bidding systems for the other three utilities represent their proposed approach, which at the time of our study, had not received final review and approval from the respective state PUCs. Thus, the final RFPs issued by the utility may differ in some respects from these initial proposals because State regulatory commissions can be expected to greatly influence competitive bidding systems. In March 1988, Boston Edison filed its second Request for Proposals with the Massachusetts Department of Public Utilities, soliciting 200 MW of capacity and associated energy from Qualifying Facilities to be in service by 1994. Orange and Rockland Utilities (ORU) and Niagara Mohawk (NMPC) filed competitive bidding guidelines and RFPs in October 1988 in

response to regulatory decisions in New York and New Jersey. ORU's and NMPC's RFPs solicit proposals to fill capacity blocks of 100 MW and 350 MW, respectively, by 1994-95. By the mid-1990s, ORU forecasts a summer peak load of 1075 MW while NMPC projects a winter peak of 6600 MW. In the near term, ORU's need for additional capacity is greater than NMPC's because NMPC currently has excess generating capacity.

The Virginia Power (VP) system is qualitatively different from the other three utilities in that VP does not provide a pre-announced estimate of avoided cost in the absence of the auction. Because the procurement envisioned by VP is large in both absolute and relative terms, the nature of individual project economics depends heavily upon the characteristics of other proposed projects. Thus, the implicit assumption of the other bidding systems, that projects are independent of one another, is explicitly rejected in this setting. Virginia Power also does not provide potential suppliers with the explicit self-scoring procedures that characterize the other three systems. To distinguish between these different approaches, we call the VP system "closed" to indicate that it is not transparent to bidders, while the other utilities have proposed systems that are "open."<sup>1</sup> The utilities with "open" systems vary with respect to the degree of reliance that they place on self-scored bids in determining winning projects. For example, Niagara Mohawk has proposed a hybrid system with two steps. In the first phase, NMPC would select an initial award group of projects based on an objective self-scoring ranking system; the capacity of the projects selected would be at least 150% of the MW requirement. In phase two, the Company would select the best mix of projects based on its multi-dimensional planning evaluation criteria and subjective judgment and then negotiate with projects in the initial award group.

### 3.2.1 Bid Evaluation Criteria

Table 3-1 summarizes the bid evaluation criteria used by each utility. We have aggregated various non-price factors into broader categories, which are listed in the first column. Some entries in Table 3-1 are given as percentages, while others are descriptive terms (given in bold face). This distinction embodies the most basic difference in the design of schemes, whether certain minimum threshold criteria will be imposed on the form of bids (i.e., constraints) or whether features will be traded off against one another through the use of weights. These four bid evaluation systems lean primarily in the direction of weights.<sup>2</sup>

We have expressed the numerical scores from each system in terms of their relative weight, normalized in terms of percent. Each evaluation system has a maximum possible score, which means that the implicit trade-offs among various factors can be calculated. It is worth noting that not all weighting systems have this property. For example, in its first request for proposals (RFP), Boston Edison computed the price score in a fashion that would allow, in principle,

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<sup>1</sup> It should be noted that open systems are difficult to develop in cases where incremental capacity needs are relatively large (compared to the existing utility system), because the value of particular features depends on the aggregate properties of all bids.

<sup>2</sup> Threshold criteria and use of weights are not mutually exclusive. In fact, those systems that rely primarily on weights in evaluation bids, often establish minimum bid requirements for some non-price factors.

unbounded scores (BEC0, 1986). The price score was determined by the ratio of avoided cost divided by the bid price. In the hypothetical case where the bid price approaches zero, the score could approach infinity. In contrast, for most of the bidding systems shown in Table 3-1, the price score is computed by benchmarking the bidders price against some ceiling price that is an estimate of the utility's avoided cost in the absence of the auction. For example, in its second RFP, BEC0 computes the price score as a percentage of avoided cost, which eliminates the unboundedness. The four bid evaluation systems are also linear in the sense that the score for each category is additive, yielding a total project score. In contrast, a system proposed by Western Massachusetts Electric Company (1988) has non-linear interactions, although we defer discussion of this approach because it is atypical.

It is also very important to recognize the difference between the nominal weight of a particular factor and its real weight, which can only be determined based on the actual distribution of bids in an auction. For example, assume two non-price factors are assigned equal weights in a scoring system (e.g., each factor is worth 5% of the total points). The bids for one factor are tightly clustered with little variation, while scores for the other attribute vary widely. In this example, if these were the only two factors, the outcome would be determined by the factor with scattered bids. That is, the real weight is determined by the actual distribution of bids and cannot be known without such information. Our discussion refers only to the nominal weights for each factor, because it is impossible to determine the real weights since, at this time, we only have information on the form of an evaluation scheme. We use this simpler approach because of data limitations, although we examine the issue of nominal versus real weights in Chapter 6 when we compare the scores for a group of generic bids.

**Table 3-1. Summary of bid evaluation systems of four utilities.**

Category	Virginia Power	Boston Edison (#2)	Niagara Mohawk	Orange & Rockland
<b>Price</b>	70%	40%	70.8%	50%
<b>Supplier Assurance</b>	10%			
<b>Development</b>		20%	5.3%	23%
<b>Longevity</b>		8%	1.7%	1%
<b>Fuel Choice and Flexibility</b>	10%	4%	1.5%	4%
<b>Environmental Factors</b>			9.2%	7%
<b>System Optimization</b>	10%			
<b>Dispatchability</b>	Virtually Re- quired	4%	4.6%	4%
<b>Other</b>			0.5%	3%
<b>Front Loading</b>	Capacity Only; 90% of PV in 15-year level payments, 10% in last 10 yrs.	20%	6.3%	20% for Oil & Gas, 35% for Solid Fu- els
<b>Contract Length</b>	25 yrs preferred	20 yrs. maximum	> 5 yrs. 15 preferred	5%
<b>Maximum Bid Size</b>		25% of Block Size		

### Price

Price is the dominant factor in each bid evaluation system (e.g., nominal weights of 40-70%), although the price score is computed differently among the utilities. For example, BECo and NMPC award bidders one point for every percentage point that the bid price is below avoided cost. Thus, maximum weight is given for a bid at zero price, and no points for a bid at avoided cost. Maximum points on price score are essentially unachievable in the BECo and NMPC systems because bidders will not make an offer at zero price. This approach has the implicit effect of lowering the nominal weight given to price in these systems. The nominal weight of price in the BECo system is 40% (100 out of 250 maximum points). If we assume that the average value of price bids is about 85% of avoided cost, then these projects would receive a price score of only 15 out of 100 points. ORU uses a variant on the percentage of avoided cost procedure, which awards the maximum score to bids at 25% of avoided cost, and decreases the score linearly until the bid reaches 100% of avoided cost.

## Non-Price Factors

The existence of non-price factors is one of the main reasons that electric power auctions are not amenable to simple oral auctions. In fact, the bulk of the detail in "open" systems is often devoted to factors that differentiate the kind of project being proposed, its likelihood of success, and the financial terms under which the bidder proposes to be paid. We now discuss these factors in more detail.

### Supplier Assurance

The features grouped in the "Supplier Assurance" category address both the near term prospects for the successful development of a particular project (i.e., "development") as well as its long-term viability (i.e., "longevity"). In one sense, the buyer wants to be protected from accepting deals that are "too good to be true." If a bidder offers an unusually attractive price, it may be due either to remarkable efficiency or unrealistic optimism. In the latter case, the utility may end up with worthless promises for a project that has little chance of materializing. It is, of course, difficult to obtain guarantees from suppliers that are truly valid indicators of realistic, achievable projects. Therefore, many of the indicators used to assess the development viability of a bid are minimum threshold criteria. Other factors are indicators of likely success or represent very mature stages of project development. The factors examined include: site control, project engineering, financing and permitting, and the experience of the developers (which are shown under the term "Development" in Table 3-1). For example, among these factors, site control, project engineering, and fuel contracts reflect minimal necessary requirements that any serious bidder ought to be able to meet. These are necessary conditions that do not provide positive information on the ability to develop. Without meeting these conditions, a project is not a serious contender. In contrast, factors such as environmental permits and firm financing arrangements are almost too stringent to be reliable indicators. Most projects cannot be expected to meet these requirements at the time of a bid. Ideally, project viability factors should be indicators of the probability of obtaining permits and financing. Additional work in this area would be useful in order to develop indicators that help discriminate on the chances of developing and operating successful projects.

"Longevity" is an explicit category only in the BECo and NMPC systems and addresses factors that would indicate long-term performance viability for the supplier. For example, assurance of long-term fuel supplies means that the project will be able to operate physically. Projections of reasonable debt coverage means that excess leverage should not cause a default on delivery. Other factors include long-term maintenance contracts and operating security deposits. ORU places somewhat less emphasis on longevity, as its bidding system awards points only for security of fuel supply.

### Fuel Choice and Flexibility

"Fuel Choice and Flexibility" factors refer to the buyer's concerns with diversity of fuel mix. The underlying issue is the risk of dependence on fuels that may come into short supply, principally oil and gas. The Virginia Power system is the most explicit on this point, and arguably places the largest value on this factor. Their RFP makes a particular point about emphasizing the value placed on coal-fired projects, especially those using coal produced in Virginia.

## Environmental Factors

There are significant differences among these utilities in the treatment of environmental factors. VP and BECo essentially ignore these issues, while NMPC and ORU give them substantial weight (7 to 9% of the total points). ORU's initial bidding proposal describes their approach in terms of benefits, using simple fuel type categories to differentiate among projects. Renewable energy and DSM projects receive the maximum score of 7 points, while cogeneration projects receive only 2 points, and all other fossil fuel projects get no points. NMPC used a more disaggregated approach, measuring project specific environmental impacts (see Appendix F for more details).

An important set of issues in evaluating fuel choice and environmental benefits is the role of public policy versus ratepayer value. Many of the benefits associated with fuel diversity and reduced environmental insult are related to the valuing of public goods rather than private goods. Because the power auction process is primarily a procurement for private consumer benefit, it is not clear what weight ought to be given to the public benefits associated with choices made in the process. The key decision-maker in this regard is apt to be the state regulatory commission. The mandate perceived by these agencies varies widely. Most typically their authority goes more to ratemaking than environmental or security policy, although there are exceptions. One notable case is the preference given by New Jersey to projects based on resource recovery. Given the growing public concern about environmental and national security issues, we expect that states and utilities will need to focus more analytical attention in the future on their policies towards public goods compared to current efforts.

## System Optimization

"System Optimization" factors address the operational fit between project characteristics and the operating procedures and problems of the utility. Dispatchability is the most important of these factors for many utilities. To match the fluctuations of demand with the real-time output of the system requires that generators vary their daily and weekly output. Private power acquired under the PURPA regulations is essentially "must take," and therefore provides very little in the way of load-following. The significance of dispatchability varies among utilities, and depends primarily on the amount of capacity that the utility has which does not have operational flexibility as well as the possibilities for economy energy transactions with other companies (e.g., trading arrangements).

Virginia Power places much more importance on dispatchability than the other three utilities (see Table 3-1). VP has made dispatchability a virtual constraint upon bidders and reserves the right to reject any non-dispatchable bidder. The company allows some limited opportunity for must-take resources, but only at the variable price of VP's own coal-based resources. The terms are not intended to be attractive, because most of these resources have extremely low variable costs. In contrast, the other utilities place lower weights on dispatchability: 4.6% for NMPC and 4% for BECo and ORU. To some extent, this difference may be accounted for by the pooling arrangements that are available to the other three companies. On the other hand, both NMPC and BECo have identified potential minimum load problems on their systems, which should increase the value of dispatchability. For example, a recent NMPC study concluded that the utility would be forced to curtail nuclear or hydro generation if only moderate fractions of the QF projects that have signed contracts actually deliver power (Niagara Mohawk,

1988b). BECo also identified this problem in their most recent integrated resource plan (Boston Edison, 1988b).

Other factors categorized under the heading of System Optimization include favorable location in the transmission grid, diversity of ownership among the set of suppliers, and unit size. By design, VP is the least transparent on these questions. They allocate 10% of the evaluation weight to such concerns in addition to the virtual requirement of dispatchability. BECo gives the least weight to system optimization.

#### Front Loading

The category called "Front Loading" addresses the timing of payments requested by bidders. Utilities typically project that the value of power will increase significantly over time in their estimates of long-run avoided costs. Generally, this occurs because of the rather low level of oil and gas costs relative to future expectations or because a utility has short-term excess capacity. Under these circumstances, bidders may need payments that exceed estimated avoided costs during the initial years of a project; these payments are "front loaded." Capital-intensive technologies are more likely to have financing constraints that require front-loaded payments (Kahn, 1988; see chapter 6). For such a payment stream to have value to the buyer, it must be substantially lower than avoided cost in the long run. Buyers perceive a risk from these arrangements even when the discounted cost of a front-loaded bid is less than the discounted avoided cost. The risk is essentially that the supplier will default before the buyer has been "paid back" for the excess payment in the early years of the contract.

The four utilities have taken very different positions towards "front-loading." Virginia Power is unique and quite accommodating toward the front-loading needs of bidders, while Boston Edison is hostile. VP requires that bidders unbundle their offer into a capacity and an energy price. VP's requirement of dispatchability means that there is no guarantee on the amount of production from any project. This creates a strong incentive to bid one's cost on the energy price, because inclusion of a profit term in the energy price would produce profit results that are unpredictable. VP does indicate that the preferred form of the capacity bid would be a 15-year level stream such that no more than 90% of the total present value was in that period and no less than 10% in the last ten years. This allows for front loading of the capacity bid relative to some hypothetical escalating stream, such as the widely used economic carrying charge approach advocated by NERA for marginal cost analysis (NERA, 1977). The economic carrying charge method "back-loads" capacity charges by structuring them to escalate at the assumed rate of inflation. The Texas Utilities Electric Company Avoided Cost Offer is a prominent example of the NERA approach applied to pricing cogeneration capacity payments (Texas Utilities, 1985).

In contrast, Boston Edison places substantial burdens on bidders that seek front-loading. Their 20% weighting consists of two elements. First, there is a measurement scheme to determine how long the ratepayer will be "exposed" to overpayments. The mechanism is similar to the Payment Tracking Accounts used in some PURPA contracts where front-loading is a feature (Kahn, 1988; see Chapter 6). Balanced against this measure of the length of exposure is a system which rewards bidders that post security for the amount of ratepayer exposure. The underlying concern addressed by these methods is that front loading is a form of loan provided to the

bidder by the ratepayer. There is some risk that the loan will not be repaid; that the bidder may stop producing before the period in which the bid price is below avoided cost to compensate, in a present-value sense, for the overpayment period.<sup>3</sup>

Because front loading is related to the capital intensity of particular technologies, several utilities have attempted to develop an adjustment to normalize for these differences. For example, ORU allows for 20% front loading by oil and gas projects and 35% for solid fuel projects, which reflects the general guidelines set out in the "Stipulation of Settlement" in New Jersey (New Jersey Board of Public Utilities, 1988). This criterion refers to the maximum deviation of bid price from the estimated avoided cost at a given time.

#### Contract Length

The length of contracts offered by utilities ranges from 5 to 25 years. Most utilities use preferences or constraints for this feature of their bid evaluation system. However, ORU is an exception; its bidding system gives points for contracts greater than 10 years, with a maximum of 5% of the total weight for a 20 year contract. Imposing constraints on the length of contracts can also have a significant effect on fuel choice. For example, the California PUC proposes to limit contracts to 15 years. This imposes limitations on suppliers using capital-intensive technologies that often require longer time periods to amortize their capital costs. In contrast, Virginia Power offers long-term contracts for up to 25 years and generous treatment of front-loaded bids, which reflects its preference for capital-intensive coal projects. The systems proposed by BECo and NMPC show little clear cut preference on contract length issues.

#### Maximum Bid Size

Maximum bid size refers to any size constraints on the capacity offered by individual bidders. The trade-off for the utility on this issue is potentially lower costs from the scale economies of large bidders versus the risk of relying too much on an individual supplier, who may not actually develop even if selected. Only BECo places constraints on the size of individual bids. BECo limits bidders to capacity that is only 25% of the capacity block desired.

### **3.3 Proposed California System**

The bidding process adopted by the California Public Utility Commission (CPUC) has a complex regulatory history and has not in fact been tested in practice. The CPUC adopted a sealed second-price procedure in which bidders are paid the bid price of the highest losing bidder. The CPUC's approach contrasts with utilities in other states which have tended to favor a first-price sealed bid (each winning bidder receives the amount of his own bid). In addition, the CPUC's proposed framework would be based largely on a system of prescribed constraints rather than multi-attribute weights. In this system, price is the exclusive factor that is used to distinguish among bids; other features are covered by minimum threshold constraints insofar as eligibility to bid is concerned. Thus, the Supplier Assurance category would involve certain minimum criteria that in the open self-scoring systems would be awarded evaluation points. The relatively easy factors such as site control, engineering drawings and fuel contracts would be

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<sup>3</sup> We analyze the specific form of the trade-off between price and front loading in the Boston Edison evaluation system in Chapter 4.

included; while the difficult requirements such as permanent financing and environmental permits would be excluded. The system proposed by the CPUC does not address all the categories identified in Table 3-1 (e.g., fuel choice or maximum bid size).

Dispatchability is treated in a rather unique fashion. The CPUC draws a distinction between the theory of avoided cost underlying the entire resource planning procedure and the subsequent optimization of the power system. The avoided cost is defined in terms of a hypothetical new facility called the "Identifiable Deferrable Resource" (IDR). The process of determining the IDR is spelled out in some detail (CPUC, 1986). Winning bidders receive prices that are some fraction of the IDR costs for the period of time the IDR would have operated. Any other production by the bidder is paid using short-run methods that are updated as system conditions change (CPUC, 1987). If the producer were to curtail output as a means of improving overall system efficiency, they would be paid for this under a special "performance adder" arrangement. The dispatchability adder would then capture the additional value of this feature beyond what was embodied in the IDR (CPUC, 1988).

Front loading is strictly forbidden under the proposed CPUC system. All capacity and certain energy payments would be strictly escalating according to a pre-specified escalation rate. This is a rigorous application of the economic carrying charge method. Power contracts would be limited to 15 years.

Although the proposed CPUC procedure has gone through a long process of development and definition, it has recently come under substantial criticism from the principal California utilities. The utilities are particularly concerned about the second-price mechanism for paying auction winners and the inflexibilities associated with relying excessively on constraints rather than weights (Pacific Gas and Electric, 1988). In fact, the two issues are linked. A second price auction is thought to have efficiency properties that are superior to the more traditional first price or discriminative auction procedure. The differences between these procedures are reviewed with particular reference to electric power in the recent literature (Rothkopf, et al, 1987). However, in practice, the second price procedure is only practical where the commodity being sold is sufficiently simple and homogeneous so that non-price features are irrelevant to the acquisition process. This condition is not met in electric power. As our brief discussion of dispatchability indicates, it is difficult to accommodate different project characteristics in a system of constraints. It is unclear whether the CPUC will revise its previous decisions on auction format to accommodate the concerns of the utilities, or continue along the path that it has been developing.

### **3.4 Consolidated Edison's Proposed Integrated Supply and Demand Auction**

Consolidated Edison's proposed bidding system is interesting because they have a unique approach to determining system effects in their economic evaluation method and because they do not assign an explicit weighting to non-price factors in the initial stages of bid evaluation (Con Ed, 1988). Instead, Con Ed proposes a normalization procedure that monetizes the non-price features of a particular bid by comparing it to a reference bid. Their basic idea is that the absolute value of non-price factors can only be determined relative to the features offered by a particular alternative resource. This is a slightly more flexible version of the CPUC's concept of an Identified Deferrable Resource. However, in Con Ed's proposal, the reference or baseline bid is not an administratively determined avoidable resource, but the least cost bid absent non-price

considerations. Once the reference bid has been determined by price considerations alone, all bids are scored on a 300 point scale. Every bid is then normalized to the score of the reference bid. For example, if project X has 20% more non-price points than the reference bid, then this percentage differential becomes the basis for a non-price dollar adjustment to the monetary value of Project X's bid. The dollar adjustment is given by the following formula:

$$\text{Non-Price Dollar Adjustment to Project X Bid} = (0.3) * (\text{Percent Excess Non-Price Points}) * (\text{Reference Bid Price}).$$

The 0.3 factor is referred to as the non-price weight in the evaluation system. Thus, if Project X had a 20% higher score on non-price points compared to the reference bid, the dollar value of this would be 6.67% of the reference bid price.

The purpose of this monetization process is to adjust bid prices for overall economic ranking. When bid ranking is conducted in dollars, there must be some adjustment procedure for the differing scale of bids. In contrast, the open point systems of BECo and ORU do this automatically, mainly by expressing the price component as a percentage of avoided cost. NMPC discusses a procedure for aggregating bids together for evaluation purposes, so that accepted quantities will match the desired quantity closely. NMPC proposes to aggregate bids together so that it can develop and compare portfolios of investment options and because it is incorrect to compare projects with unequal lifetimes and project scales directly (Flaim, 1989). PG&E, which proposes to rank bids by dollar benefits, must use benefit/cost ratios or some other normalization method or its approach will favor bidders offering larger quantities of power.

Con Ed uses two approaches to normalize for project size. The first is a "make-up energy cost" which is assigned to bids that offer smaller amounts of power than the largest bidder. This quantity is calculated by simulation methods in some not too clearly specified manner. It would appear that the make-up energy adjustment favors large-scale, low variable cost projects. The second normalization involves the ultimate figure of merit, which is rate impact. Con Ed's primary evaluation criterion is minimization of rates over the long term. The purpose of monetizing the non-price factors is to provide some way to estimate long run rate effects. Because Con Ed also uses its framework to evaluate demand-side bids, the rate impact measure is also compatible with that goal. In the case of demand-side bids, the quantity adjustment involves incorporating reduced sales in the rate calculation.

Con Ed's proposed bid evaluation system has not yet been accepted by the New York Public Service Commission; its features will certainly become clearer over time. The idea of making the non-price evaluation more endogenous is useful, but the relative ranking effect would emerge under any other scheme. Con Ed's method of monetizing non-price factors is somewhat arbitrary, although it is difficult to determine whether this approach introduces perverse incentives without a more detailed analysis.

### 3.5 The Impact of Auction Design on Technology Choice

There are clearly many choices available in designing auction procedures for new electric generating capacity. In some cases, the resulting design indicates a utility's conscious preference for particular technologies. In other cases, the bidding systems appear to embody preferences that have the indirect effect of favoring or hindering particular types of projects. We

conclude our examination of bid evaluation systems with a brief discussion of features that tend to work against capital-intensive technologies as well as the ostensible rationales for these design choices.

We have previously identified front loading, explicit fuel preferences, and contract length as features that may critically affect the prospects for capital-intensive technologies. Systems such as BECo's, which strongly penalize front loading, will end up encouraging fuel-intensive projects. In contrast, ORU adjusts its measure of front loading impact by factors that explicitly benefit certain capital-intensive technologies. Bid prices for solid fuel projects are allowed to be greater than the utility's avoided costs in the initial years of the project by 35%, while oil- and gas-fired projects are limited to 20%.

The rationale for specifying contract length periods relates to perceptions of risk. The proposed California system is designed to limit ratepayer exposure to long term contracts by fixing a maximum length of fifteen years. The cost of this approach is an implicit commitment to oil and gas fuel price uncertainty. Ironically, because indexing provisions are typically used in setting the avoided energy payments, in most cases, ratepayers would bear the risks associated with uncertainties in oil/gas price. Thus, while the California system is consistent in its bias toward liquid fuels, the choice is not made explicitly as a policy statement, but only as the residual of nominal concerns about contract rigidities and the minimal financing needs of fuel intensive suppliers.

Finally, we note that some capital-intensive technologies are more attractive if economies of scale can be captured. However, several auction design features can affect the size of individual projects. We have already discussed possible constraints imposed by utilities that limit the size of individual projects. For example, BECo limits the bidders to projects that are no more than 25% of the total quantity to be purchased. In this solicitation the total quantity being sought is 400 MW, so the maximum individual bid would be 100 MW. This is not large enough to capture all potential scale economies.

Even where there is no explicit limit on individual bids, if the utility's resource need is small, then the effect would be the same. For example, Orange and Rockland is a relatively small utility which needs only 100 MW of additional capacity. In these situations, it would be socially beneficial for some market aggregation mechanism to operate so that scale economies can be realized. One possible alternative would be to organize power purchase and evaluation decisions at the level of individual states. Regulatory control would still be operative at the state level, but scale economies could be realized and the benefits allocated to small utilities on the basis of joint participation. At least one state PUC (e.g., Vermont) is considering a scheme of this kind.

A final consideration where scale economies are concerned is the viability of linear scoring systems. The implicit assumption of the linear approach is that project economics do not interact with one another or with the underlying system. Once scale economies begin to be realized these assumptions may no longer be valid. At that point, other evaluation methods may be needed. We will discuss this issue of non-linear effects in more detail in Chapter 5 when we analyze large-scale procurements, such as that conducted by Virginia Power.

## **4. THEORETICAL ASPECTS OF BID EVALUATION: MEASURING AND PRICING RISKS**

### **4.1 Overview**

In Chapter 3, we surveyed various approaches used by utilities to evaluate price and non-price factors. Design choices are often motivated by the perception of risk and uncertainty on the part of the utility (and/or regulator). In addition, private power producers potentially face greater risks than the utility, because the seller may be much less diversified. The seller's costs, some of which are highly uncertain, must be covered by a revenue stream sufficient to attract capital. The consequences of miscalculation are project failure. Although project failures also impact the utility, the utility's risk is likely to be spread over many projects. Therefore, the design of contract terms must balance the risk-sharing function between buyer and seller with incentives that encourage private developers to perform efficiently.

In this chapter we examine the approach adopted by several utilities to measuring and pricing risks in their bid evaluation systems. It is not possible to treat this subject exhaustively because in many cases an adequate conceptual framework does not exist. Moreover, in some cases, data to estimate the magnitude or price of risk are weak. Our treatment is exploratory and focuses on two areas that impact capital-intensive technologies: front-loading and fuel diversity. We present an economic framework to evaluate front-loaded bids and use it to illustrate the undue burden implicit in the BECo bid evaluation system. This model is flexible enough to be incorporated into most scoring systems. In Chapter 2, we described briefly how utility concerns about fuel diversity can benefit capital-intensive technologies.<sup>1</sup> This argument is generally accepted, although there is considerable conceptual ambiguity regarding who accrues the value of fuel diversity. We examine the range of potential answers to this question, and make estimates in some of these cases.

In addition, we briefly discuss approaches to evaluating the environmental impacts of generating resources and review the treatment of risk in project viability (i.e., the supplier assurance category in Chapter 3) and a related issue, the costs of mitigating project failure. Project viability, the danger that bidders who are awarded contracts will not actually deliver as promised, is a major risk for the utility. We review the value and cost dimensions of several insurance mechanisms that reduce or eliminate the costs of failed or abandoned projects. Our analysis suggests that measurement of project viability and project failure insurance mechanisms are areas in which additional research is needed.

### **4.2 Front Loading of Payments**

Figure 4-1 illustrates the fundamental issue involved in front-loading in a simple schematic fashion. The utility's expected avoided cost trajectory, which escalates over time, is shown along with a fixed price bid, which is constant over the lifetime of the project. Note that the present value (PV) of the utility's avoided cost is greater than the fixed price bid. Therefore, the

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<sup>1</sup> See Section 4 in Chapter 2.

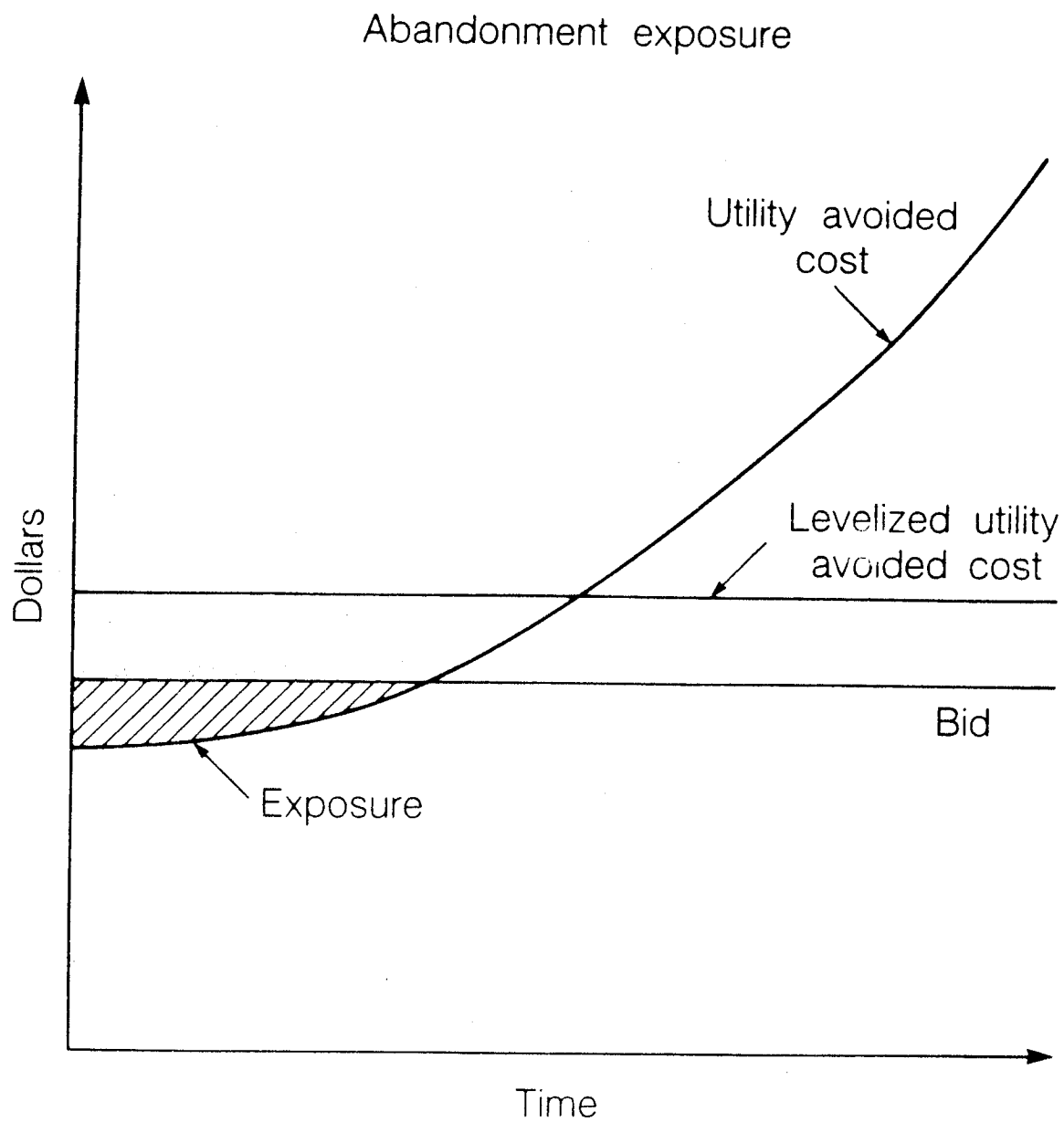


Figure 4-1 shows ratepayer exposure risk for front-loaded bids.

bid is preferable to avoided cost, all other things being equal. However, the bid price exceeds avoided cost in the initial years of the project, which reflects the seller's preferred payment stream. The seller's payment stream creates an exposure to the risk of project abandonment, which is shown by the hatched area. At some later point in time, as avoided costs increase, the present value benefits of the low bid price equal the present value exposure and the economic risk is eliminated.

Some utilities and regulators view front-loaded bids as undesirable because they believe that they are in effect subsidizing the project in its initial years by providing loan financing to the developer. Our method of evaluating front-loaded bids is based on a formalization of this intuition.

#### **4.2.1 Front-Loading as a Loan**

We want to model the economic relationships involved in front-loading to yield a systematic procedure for evaluating such bids. We rely on the intuition that front-loading is like a loan, but formalize this notion in a consistent fashion (see Appendix A for a more in-depth discussion of the implicit loan method).

We begin qualitatively by considering two bids that have the same present value as the utility's avoided cost. The only difference between the bids is that one is front-loaded. The first bid is equal at every point to the utility's avoided cost stream, which we call a neutral bid. The second bid is front-loaded and we believe intuitively that it is worse from the standpoint of risks to ratepayers than the neutral bid. We then separate the front-loaded bid into two components: Part A, which is equal to the first bid at every point, and Part B, which is just the difference between the first bid and the front-loaded bid. Part B has a negative cash flow in the early years, which is then followed by a positive cash flow. The positive cash flows in later years are greater in absolute value than the negative cash flows initially, so that they are equal in terms of discounted present value. The basic pattern of negative cash flow followed by compensating positive cash flow looks like the pattern of a loan.

We want to account for the intuition that front loading is worse than neutral streams. One way this can be represented is to assume that the present value of Part B is actually negative rather than zero. To achieve such a numerical result (i.e., negative PV), the discount rate for Part B must be higher than normal. The rationale for introducing a higher than normal discount rate is to account for the risk that some of these loans will not be repaid. Lenders normally apply a risk premium to compensate for the probability of loan default. In our context this means that front loaded bidders may not supply power at the end of their proposed contract, which we interpret as a default on the implicit loan.

Conceptually, then we can describe the appropriate technique for evaluating front-loaded bids as a process of separation into a neutral and a loan component. The neutral part will be treated like any other bid (i.e., it will be evaluated at the utility's normal discount rate). The loan part will be discounted using a risk premium over and above the utility's normal discount rate. To formalize this concept, we must specify the meaning of neutrality, which will then allow us to define how to separate a bid into components.

Our approach, called the implicit loan (IL) method, rests on two assumptions. First, the utility's avoided cost stream defines neutrality. The neutral part of a bid should be proportional to the avoided cost. Second, the loan component is measured over the entire proposed contract length. It will be discounted at a risk-adjusted rate so that its present-value at that rate is precisely zero at the end of the power contract term. Algebraically, we can describe the IL method using Equations (1) and (2) based on the definitions given in Table 4-1.

Table 4-1. Definitions used in Implicit Loan method.

$C(t)$	The bidder's total bid stream, defined as $C(t) = P(t) + L(t)$
$P(t)$	The neutral component of $C(t)$ .
$L(t)$	The loan component of $C(t)$ .
$A(t)$	The avoided cost stream.
$r$	The utility's regular discount rate.
$R$	The loan interest rate ( $r$ + risk premium).
$PV_R[ Y(t) ]$	The present value <sup>†</sup> of stream $Y$ at rate $R$ .

$$C(t) = b \cdot A(t) + L(t) \quad (1)$$

$$PV_R[ L(t) ] = 0 \quad (2)$$

The first equation separates the bid stream into its neutral and loan components. The parameter " $b$ ," which we call the "price factor," is the proportionality constant defining the neutral component. It will be very useful as a means of incorporating the front loading risk directly into the price score, however that may be computed. The second equation defines the condition on repayment of the loan.

Figure 4-2 is a graphic illustration of the IL method. Initially, the bid payment stream,  $C(t)$ , is above the utility's avoided cost in the first 3-4 years, and is less than avoided cost in later years. The separation technique transforms the payment stream into its neutral component,  $P(t)$ , and the loan component. We show the loan component in its cumulative form,  $X(t)$ , where the area under the curve shows the cumulative exposure at any point in time. By Eq.(2),  $X(t) = 0$  when the contract ends.

The IL method uses two parameters to characterize a front-loaded bid,  $b$  and  $R$ . These are mutually dependent. The loan interest rate,  $R$ , is higher when the loan is considered riskier. This means that the repayments (i.e.,  $P-C$ ), must be larger to offset the period when  $C-P$  is negative (which is the "implicit loan"). Therefore, a larger value of  $R$  means a larger value of  $b$ , which is the same as saying that the price score moves closer to avoided cost. Thus, the bid is less favorable to the utility. This inter-relation between  $b$  and  $R$  is the way in which the IL

<sup>†</sup> Present value is defined either as  $\sum_{t=0}^T \frac{Y(t)}{(1+R)^t}$ , if payments are made at the beginning of each year, or as  $\int_0^T Y(t) \cdot e^{-Rt} dt$ , if payments are made continuously.

## Evaluation of Front-Loaded Bids: The Implicit Loan Method

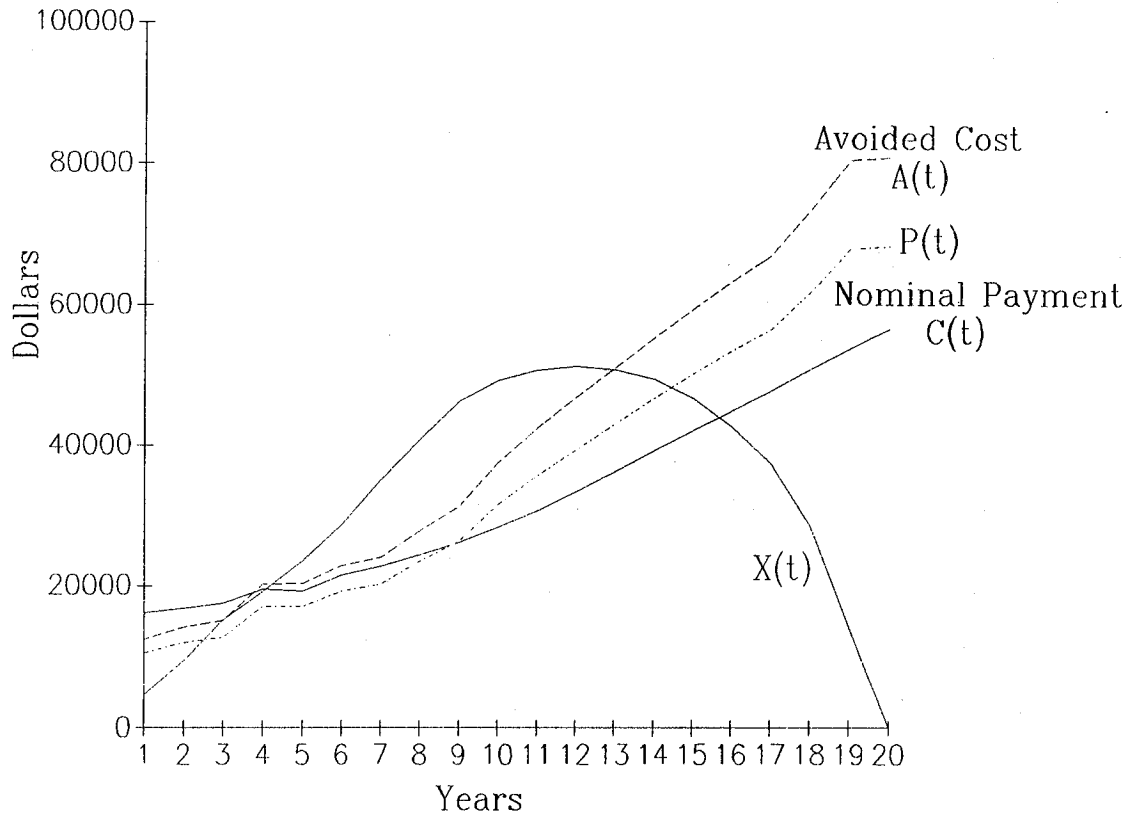


Figure 4-2 illustrates our approach to evaluating a front-loaded bid, called the Implicit Loan Method. Nominal payments,  $C(t)$ , to bidders exceed the utility's avoided cost,  $A(t)$ , in the first four years of the project.  $P(t)$  represents the "neutral" payments, which are proportional to the utility's avoided cost.  $X(t)$ , represents the cumulative loan overpayment, which must be repaid by the end of the contract term.

method rolls front loading risk into the price evaluation. We solve for  $b$  by re-arranging Equation (1) and then substituting for  $L(t)$  in Equation (2):

$$\begin{aligned}
 C(t) - b \cdot A(t) &= L(t) \\
 PV_R[ C(t) - b \cdot A(t) ] &= PV_R[ L(t) ] \\
 PV_R[ C(t) ] - b \cdot PV_R[ A(t) ] &= 0 \\
 b &= \frac{PV_R[ C(t) ]}{PV_R[ A(t) ]} .
 \end{aligned} \tag{3}$$

Equation (3) gives us  $b$ , the "price factor" which is the ratio of the present values of the total bid stream and the avoided cost at rate  $R$ . Notice that the utility's normal discount rate does not even enter the calculation. If we know  $R$ ,  $b$  is found easily. Conversely if we know  $b$ , we can find  $R$  by iteration. The IL method can be applied to analytic problems starting at either point.

The ideal use of the IL method is to develop a measure of the riskiness of a front-loaded bid and compute the risk premium associated with it. The risk premium should then be added to the normal utility discount rate to find  $R$ , and then  $b$  can be computed. We can define a reasonable range for the risk premium based on a cursory examination of financial market data. For very risky borrowers, the risk premium may exceed 5%. It should be substantially less for safer loans.

We will also use the IL method to compute the implicit interest rate embodied in bid evaluation schemes that use points to penalize front loading. For this application, we construct an equivalent bid without front loading (i.e., a neutral bid) that receives the same score as the front-loaded offer. We can then find the price penalty imposed by the evaluation scheme and the implied interest rate.

#### 4.2.2 Application of Implicit Loan Method to BECo and NMPC Bidding Systems

To illustrate the perspective which the IL method provides, we examine the approach proposed by Boston Edison (BECo) and Niagara Mohawk Power Corporation (NMPC) in their draft RFPs to evaluate front-loaded bids.<sup>2</sup> BECo measures front-loading in terms of an implied loan maturity. The project developer must prepare a worksheet in which the annual over-payment of the developer's bid is compared to the utility's avoided cost (see Table 4-2, columns 1 and 2). Note that the over-payment (shown in column 6) is negative when the developer's bid price is lower than the avoided cost. The annual over-payments are accumulated, with interest charged at the utility's normal discount rate (column 7). The accumulated balance is reduced and ultimately liquidated as avoided costs exceed the bid price in the later years of the project. In

<sup>2</sup> It is important to note that BECo's final scoring system (BECo, 1989) in RFP#2 as adopted by the Massachusetts Department of Public Utilities is somewhat different from the utility's draft proposal that we analyzed. Differences in relative weights given to price factors and economic confidence factors would affect our resulting calculation of the implicit loan rate for this project.

BECo's system, the number of years until liquidation of the accumulated over-payment, called the break-even score (column 8), is the key indicator of front-loading. The break-even score is effectively a measure of the length of the front-loading loan. Other loan parameters of possible interest, such as the magnitude of the exposure or its risk, are ignored by BECo.

Table 4-2. BECo's scoring of front-loaded bids: Calculating the breakeven score.

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			PV factor at 10.88%	PV of Payments	PV of Avoided Cost	Over Payment	Cumulative Over Payment with Interest 10.88%	Break Even Score
Year	Nominal Payments C(T)	Nominal Avoided Cost A(T)						
1990	16144	12510	1.000	16144	12510	3634	3634	0
1991	16864	14244	0.902	15209	12846	2620	6649	0
1992	17590	15111	0.813	14307	12291	2479	9852	0
1993	19533	20240	0.734	14329	14847	-707	10217	0
1994	19261	20325	0.662	12743	13447	-1064	10264	0
1995	21496	22841	0.597	12826	13629	-1345	10036	0
1996	22744	23992	0.538	12239	12911	-1248	9880	0
1997	24345	27829	0.485	11815	13506	-3484	7471	0
1998	26154	31298	0.438	11448	13699	-5144	3140	0
1999	28361	37529	0.395	11195	14815	-9168	-5687	1
2000	30759	42422	0.356	10951	15103	-11663	-17968	2
2001	33405	46707	0.321	10726	14997	-13302	-33225	3
2002	36260	50992	0.290	10500	14766	-14732	-51572	4
2003	39270	55290	0.261	10256	14440	-16020	-73203	5
2004	42058	59475	0.236	9906	14008	-17417	-98585	6
2005	44867	63463	0.212	9531	13481	-18596	-127907	7
2006	47767	67017	0.192	9151	12839	-19250	-161073	8
2007	50883	73521	0.173	8792	12703	-22638	-201236	9
2008	53830	80705	0.156	8388	12576	-26875	-250005	10
2009	56791	81035	0.141	7981	11388	-24244	-301450	11
			SUM	228437	270801			11
				SPVB	SPVC			B.E. YRS

Table 4-2 is a facsimile of BECo Evaluation Sheet #5 for a hypothetical project with a front-loaded bid (Project A).<sup>3</sup> This project would receive 15.6 price points because the ratio of the sum of present-value payments to the bidder (Sum PVB) to the sum of present-value avoided costs (Sum PVC) is 0.843. The bidder computes the score for front-loading by determining the number of years in which the cumulative overpayment with interest is negative. In this example, the front-load loan has been repaid by year 9. The bidder subtracts this number of years from the maximum number of years allowed for a long-term contract (20 years) to give 11 years. The

<sup>3</sup> The bid data were taken from an example included in the Western Massachusetts Electric Company RFP. Note that the avoided costs are a somewhat smoothed version of the BECo estimate.

breakeven score (i.e., number of years) is then multiplied by 1.5 to determine the actual points assigned to this category. Thus, this project would receive a breakeven score of 16.5 points, out of a maximum possible 30 points. Projects with front-loaded bids can receive additional points (20 points maximum) by posting financial security for the cumulative over-payment. The bidder receives 20 points in the front-load security category if cash-equivalent financial security is posted that is equal to 100% of the over-payment amount. Projects that are not front loaded receive the 20 points automatically. There is proportional downward adjustment for lesser security in terms of the number of points that can be earned.

The BECo system implies very heavy penalties for front-loading. This can be demonstrated by using Equations (1)-(3) to compute the implicit loan interest rate that BECo is charging for Project A. To determine this interest rate, we create a comparable project (Project A\*) that receives the same total score as Project A, but which is not front-loaded (see Table 4-3). We separate total cash flows for each project into payment and loan components according to Eq.(1); note that total cash flows are equal.

Table 4-3. BECo's scoring of a front-loaded bid with additional security.

Project A		Project A* (without front-loading)	
	Points		Points
=====		=====	
Price Factor	= 15.6	Equivalent Price Factor	= 2.1
Breakeven Score	= 16.5	Breakeven Score	= 30.0
Front Load Security	= 20.0	Front Load Security	= 20.0
	-----		-----
Sum	= 52.1	Sum	= 52.1
		SPVB/SPVC = b =	0.979
		====> R =	24.7%

We assume that Project A posts full security for the over-payment, and receives 20 points in this category. The total score for Project A is then 52.1 points, which is the number of points that Project A\* must by definition receive to be a comparable bid. Because Project A\* is not front-loaded, the project is awarded 30 points for the breakeven score and 20 points for front-load security automatically (50 points total). Project A\* must then receive only 2.1 price factor points in order to have an identical bid to Project A, which means that Project A\* bids at 97.9% of the utility's avoided cost (and the parameter  $b$  is 0.979). We then use Eq.(3) to find Project A\*'s risk-adjusted interest rate  $R$  that is implied by this choice of  $b$ . We solve this problem iteratively and determine that  $R = 24.7\%$  (see Appendix A for detailed calculations).<sup>4</sup> This result means that BECo's bid evaluation system effectively charges Project A an implicit loan interest rate of 24.7% for its front-loaded bid, which implies a risk premium of about 14%. Moreover, our example assumes that the bidder has posted full financial security for the cumulative over-payment. Because the score for security is high relative to price, it is instructive to repeat this

<sup>4</sup> Note that our solution must also satisfy the constraint imposed by Equation (2); that the implicit loan for Project A\* is paid off by year 20 at a loan interest rate of 24.7%.

calculation for a situation in which Project A decides not to post any financial security, and thus receives 0 points in this category (see Table 4-4).

Table 4-4. BECo's scoring of a front-loaded bid without additional security.

Project A	Points	Project A* (without front-loading)	Points
=====		=====	
Price Factor points =	15.6	Equivalent Price Factor =	-17.9
Breakeven Score =	16.5	Breakeven Score =	30.0
Front Load Security =	0.0	Front Load Security =	20.0
	-----		-----
Sum =	32.1	Sum =	32.1
		SPVB/SPVC = b =	1.179
		==> R =	67.4%

Project A now receives a total score of only 32.1 points in these three categories. However, Project A\*, the equivalent bid, is still awarded a total of 50 points in the breakeven score and financial security categories, because it is not front-loaded by our definition. To reconcile the two characterizations, the equivalent bid must receive a negative price factor score! We perform the computation to illustrate the absurdity of the situation. In this case, Project A\* must receive -17.9 price factor points in order to have an identical total score (32.1 points), which would correspond to  $b = 1.179$ . Project A\*'s bid is then 18% above avoided cost, which violates the threshold constraint imposed by BECo that bids can not exceed the utility's avoided cost. The implicit risk-adjusted interest rate would be 67.4%.

The results for Project A under BECo's proposed system are driven largely by the relatively high weights given to the breakeven score and front-load security factors relative to price. For comparison, we repeat the calculation using Niagara Mohawk's (NMPC) proposed bid evaluation system. NMPC's approach is identical to BECo's system with one significant difference. NMPC gives a much higher relative weight to the price score compared to the economic risk factors. The maximum points awarded for price, the breakeven score, and front-load security in NMPC's system are 850, 50, and 25 points respectively. Table 4-5 summarizes results for Project A under NMPC's bid evaluation system for the two extreme cases: the bidder posts full financial security and situations in which no additional financial security is offered.

Table 4-5. NMPC's treatment of front loading.

Full Security		Project A* (without front-loading)	
Project A	Points		Points
=====	=====	=====	=====
Price Factor	= 133.0	Equivalent Price Factor	= 110.5
Breakeven Score	= 27.5	Breakeven Score	= 50.0
Front Load Security	= 25.0	Front Load Security	= 25.0
	-----		-----
Sum	= 185.5	Sum	= 185.5
		SPVB/SPVC = b = 0.870	
		====> R = 13.2%	
No Security		Project A* (without front-loading)	
Project A	Points		Points
=====	=====	=====	=====
Price Factor points	= 133.0	Equivalent Price Factor	= 85.5
Breakeven Score	= 27.5	Breakeven Score	= 50.0
Front Load Security	= 0.0	Front Load Security	= 25.0
	-----		-----
Sum	= 160.5	Sum	= 160.5
		SPVB/SPVC = b = 0.899	
		====> R = 16.3%	

The loan interest rates for Project A that are implicit in NMPC's scoring system (13-16%) are certainly more reasonable than those contained in the BECo system (25-67%).<sup>5</sup> For comparison, risky bonds are priced in the high-yield debt markets at interest rates that typically range from 12-20%. Those bonds with rates at the high end of the range are either in default or expected to go into default. Thus, NMPC's scoring system and relative weights reflect risk-adjusted interest rates for front-loaded bids that are comparable to junk bonds. Our analysis shows that BECo is severely penalizing front-loading, and that NMPC's weights, at least for this example, are more sensible. However, it is also important to address the more fundamental question of whether each utility's basic approach to evaluating the risks associated with front-loading makes sense. The Implicit Loan (IL) model embodied in Equations (1-3), at least provides a rational framework for constructing a sensible evaluation scheme. We can also outline the elements that are necessary for translating the IL method from a simple conceptual framework that can be used to interpret point systems to an analytical approach that provides a superior alternative to current scoring systems, which often assign weights to various categories arbitrarily (see Appendix A).

The basic element that is missing from the IL method is a relationship between the characteristics of the implicit loan embodied in front-loading and a reasonable risk-adjusted discount

<sup>5</sup> It is not possible for us to evaluate the utility's rationale for their weighting factors because BECo and NMPC were not required to provide supporting analysis that substantiates the weights and factors used in their scoring systems.

rate. Clearly, such a relationship should account for the degree of exposure incurred by the buyer, some measure of the maturity of the loan, and the credit-worthiness of the borrower. These are standard problems in project finance and the front-loading problem does not alter them in any fundamental way. Incorporation of these additional risk factors into the IL model is another useful research topic that could improve existing bid evaluation systems.

### 4.3 Fuel Diversity

Capital-intensive technologies are substitutes for oil and gas consumption. The value of this substitution depends upon the level of oil and gas prices, which are quite uncertain in the long run and unpredictable. One way to think about the value of fuel diversity is in terms of insurance. Over the long-term, electric bills are a gamble. They depend on uncertain future oil and gas prices to the degree that the utility depends on these fuels. Choosing solid fuel or renewable energy technologies will reduce the variability of future electricity revenue requirements. Our willingness to pay a premium for this reduction in variability reflects the insurance value of fuel diversity.

It is useful to inquire where this risk premium comes from and how it relates to ordinary economic evaluation criteria. Let us assume that we have an economic agent who is aware that there is a roughly equal chance that either "good" or "bad" outcomes of similar magnitudes could occur with respect to future energy costs. We assert that "bad" outcomes are relatively worse for many economic agents compared to the beneficial effects of "good" outcomes. This view is illustrated in Figure 4-3, which plots total utility energy costs against an abstract measure of value, called "points," which would represent the utility function of the agent to an economist.

We represent the uncertainty in this situation using a simple, two-point probability distribution. There is a 50% chance that total utility energy costs will be \$110 billion, and a 50% chance that these costs will only be \$90 billion. The expected value is \$100 billion, which is the value that would be used if risk preferences were not considered. However, Fig. 4-3 shows that the expected utility of this economic agent corresponds to a cost higher than the expected value. This means that if all uncertainty could be eliminated, and the economic agent could obtain the average utility of the high and low cost outcomes (in this example 98 "points"), then the agent would pay \$103 billion rather than \$100 billion. The difference between the certain equivalent cost and the expected value is called the risk premium. It arises because the utility function of the economic agent is curved; falling faster in the high cost case than it rises in the low cost case. This example represents a "risk averse" actor; the degree of risk aversion is represented by the curvature of the utility function.

We estimate the value of fuel diversity by applying the conceptual framework shown in Fig. 4-3 to the particular situation of the electric utility power purchase decision. The most difficult problem that must be confronted is identifying whose utility function we are trying to estimate. There are many economic agents involved in the electric utility power purchase decision. We must be clear regarding to whom we imagine the value of fuel diversity accrues in order to use the risk premium notion. We examine the various approaches that can be taken to this question and estimate the value of fuel diversity for one of these decision-makers: the average electricity consumer.



#### 4.3.1 Risk to Whom?

Many economic agents are effected by the power purchase decision. The most direct impacts are on ratepayers, and they, in some sense, represent the principal perspective from which risk evaluation ought to be conducted. Even within the broad category of ratepayers, there are important distinctions. It is well known that risk aversion (i.e., the curvature of the utility function) differs by economic status. The poor are commonly perceived to be more risk averse than the wealthy. The intuition behind this observation is that high cost outcomes curtail the consumption of basic necessities for the poor, whereas they may only impact discretionary spending among median or upper income groups. Another important distinction among ratepayers involves the potential bypass customer. This is usually a large industrial electricity user with the potential to cogenerate and leave the utility system if rates become too high. The role of bypass actually highlights the stake of other economic agents, namely managers and shareholders.

Both managers and shareholders are affected by fuel price risk, but in ways that differ significantly from the typical ratepayer. For the typical ratepayer, fuel price risk impacts their consumption behavior. If electricity bills are higher, then there is less money available for purchasing other goods and services. The problem of high utility rates is quite different for managers. In the extreme case, the manager could lose his job if utility rates are too high and many large customers decide to leave the system. Even in anticipation of such outcomes, the utility may reduce employment levels as a means of lowering costs and retaining customers. This situation has a potentially larger impact on managers than any form of price risk may have on consumers, because the manager is not diversified compared to the consumer. Electricity is only one good purchased by the consumer; thus price risk in this dimension only impacts welfare through that fraction of the budget spent on electricity. It is unusual for this fraction to exceed 10% for residential households, while, on average, electricity accounts for less than 5% of a household's total budget. On the other hand, utility managers have only one job and job loss is an extremely bad outcome.

In principle, utility shareholders are affected more directly than managers by price increases that induce large scale bypass because their earnings could be reduced. The role of the regulator is critical in such a scenario. First, we assume that fuel prices rise due to exogenous circumstances. The utility then raises rates to recover costs, which may induce some industrial customers to bypass the utility's system. To maintain the same level of earnings as before bypass, the utility must raise rates to remaining customers. The regulator delays this process or refuses to make the entire adjustment, therefore earnings fall. If the regulator had raised rates completely, it may have induced further bypass.

In this hypothetical scenario, the welfare of utility shareholders is reduced if energy cost increases result in reduced earnings. To the degree that shareholders are diversified, the magnitude of this effect is reduced. Any estimate of the risk premium of shareholders must include at least three components. First, if the principal effect lies through bypass, some model of the bypasser's elasticity with respect to price is needed. Second, shareholder returns only go down because the regulator will not promptly restore earnings lost through bypass to their previous level. Thus, some model of regulatory policy is required. Finally, to capture the diversification of shareholders, some account must be taken of the capital market response to utility-specific

events such as bypass-induced earnings loss. A common approach to such problems is to study stock prices using an equilibrium approach such as the capital asset pricing model. Needless to say, this type of analytic effort represents a major undertaking.

The problem of estimating a risk premium from the managerial perspective is only slightly less formidable. The manager's interest is not necessarily identical with the shareholder's interest. As noted previously, the manager is less diversified than the typical shareholder and faces "employment risk" if the firm's profits are low. This situation may lead managers to minimize the variability of firm profits, even at the cost of a lower average level. In regulated industries this bureaucratic tendency may be even more exaggerated than in unregulated industries. The risk aversion behavior of managers therefore will be directed toward reducing the variance of profits. Decisions about asset allocation or long-term purchase terms will be influenced by the co-variance of returns from a particular decision with the portfolio of other assets of the firm. In this setting, the managerial risk premium can be thought of as that reduction in expected return which is acceptable in exchange for a low or negative co-variance with the return on other assets. Making such a definition operational is difficult, although Helfat (1988) has recently conducted such an exercise, which focused on the U.S. petroleum industry.

#### 4.3.2 Ratepayer Benefit of Fuel Price Diversity

We analyze the simplest case, the ratepayer perspective, in order to develop a more concrete feeling for estimating the risk premium associated with power purchase contracts. Our example illuminates some of the issues associated with other perspectives. For the case of the typical ratepayer, we can adapt the framework represented by Fig. 4-3 in a straight-forward manner. Our approach relies on a treatment of this problem developed by Newbery and Stiglitz (1981) in the context of commodity price stabilization. They derive an expression for the monetary benefit  $B$  of removing risk as a fraction of the consumer's expenditure on the source of risk  $X$ .  $B$  is just the risk premium as previously discussed, and  $X$  is the expenditure on electricity. The method results in an approximation that can be used for estimating  $B/X$ , the risk premium as a fraction of the expenditure on electricity. The approximation is given by:

$$B/X = -R \cdot CV(Y_h) \cdot CV(P) \cdot r(Y_h, P), \quad (4)$$

where  $R$  = relative risk aversion,  
 $CV$  = coefficient of variation,  
 $Y_h$  = household income,  
 $P$  = price of electricity,  
and  $r$  = the correlation coefficient.

The relative risk aversion parameter ( $R$ ) is a measure of the curvature of the utility function. Arrow (1970) gives the precise technical definition and argues that its typical value is one.  $R$  is equal to zero for risk neutral actors; for risk lovers, it is negative, and for the extremely risk averse (e.g., the very poor), a practical upper bound for  $R$  is two. The coefficient of variation ( $CV$ ) is defined as the ratio of the standard deviation of a probability distribution to its mean. The  $CV$  is a simple number that characterizes the diffuseness or uncertainty of a quantity

estimate. To estimate Eq.(4) we must know how uncertain the distributions of household income and electricity price are as well as the correlation of these variables.

It is useful to describe the interaction of the terms in Equation (4) qualitatively before proceeding to estimate their individual components. It is generally assumed that electricity price and household income are negatively correlated. All other things being equal, an increase in the price of electricity will be associated with a decrease in household income, and vice versa. In this case, we are referring to macroeconomic effects. If electricity costs increase, productivity is adversely affected, which ultimately reduces income available for households. Conversely, when electricity costs go down, productivity increases and household income goes up. Note that the negative sign of this correlation cancels the negative sign that is contained in the entire equation. This indicates that there is a positive consumer benefit to stabilizing the price of electricity. The magnitude of the benefit depends on 1) the variability of income (i.e.,  $CV(Y_h)$ ), 2) variability in the price of electricity (i.e.,  $CV(P)$ ), and 3) on the degree of risk aversion (i.e.,  $R$ ). If the two CV's are small, then the value of certainty must be less; and conversely.

To apply Eq.(4) to our problem, we transform and present the price and income variables in terms that are more appropriate for our context and can readily be estimated. We express the price of electricity as the sum of a fixed and a variable component. The variable component is primarily fuel. Purchased power substitutes primarily for fuel. The value of reducing fuel price uncertainty will depend on how much of the electricity bill is due to fuel costs. We also need to develop a relationship between household income and fuel prices, which is used to estimate the value of the correlation coefficient (see Appendix B for details of these calculations and full derivation of the equations).

We draw on several available data sources in order to derive our estimates. We use a recent DRI forecast of future natural gas prices, which includes high, medium, and low price trajectories over twenty years. DRI assigns a 20% probability to the high and low case, and a 60% probability to the medium case. We can derive a CV of prices from this forecast. The natural gas price forecast shows a CV in real terms that ranges from a maximum of 40% to a minimum of 23% (see Appendix B, Table B-2). The CV of electricity prices is some fraction of these estimates, reflecting the fuel mix of our hypothetical electric utility. Since the utilities for which fuel diversity is likely to be valuable are heavily dependent on oil and gas, that fraction should be relatively high. We assume that 60% is a reasonable upper bound.

A second key estimate is the linkage between income and fuel prices. We draw upon studies that were conducted in the context of determining the optimal size and value of the U.S. Strategic Petroleum Reserve. The value of stockpiling oil depends fundamentally on the amount of economic damage that fuel price increases can inflict upon the economy. Storage is the basic form of insurance for price stability in commodity markets, so the framework involved in analyzing that problem is closely analogous with the fuel diversity problem in which we are interested. We rely on empirical estimates based on a recent study by Huntington (1986), in which he found that a \$1/barrel increase in the cost of oil results in a \$4 billion loss in real purchasing power.

Finally, we must select an appropriate value for the relative risk aversion parameter ( $R$ ). We can think in terms of some average ratepayer whose risk preferences reflect the population at

large. The key distinction is between the low-income consumer whose exposure to risk is large ( $R = 2$ ) and the typical consumer ( $R = 1$ ). We assume that 20% of the population falls into the low-income category and 80% falls into the second category, which implies a representative value of  $R = 1.2$ . The results of estimating Eq.(4) for each year of forecast data range from 0.22% to 0.55%. Taking the present value of this series for real discount rates in the range of 0% to 12% results in very stable estimates of 0.40%. DRI natural gas price forecasts are updated and revised periodically (although they are always in the same probabilistic format). As a check on the stability of our results, we used a different DRI forecast which resulted in a present- value estimate of  $B/X$  of 0.43% (see Appendix B for details).

Eq.(4) is not quite the correct formulation for use in a bid evaluation framework. As estimated it gives the consumer risk premium for stabilizing the entire electric bill. Before this estimate can be applied to the bid evaluation framework, it must be modified to account for the difference between the retail price to the consumer and the wholesale price to the utility. For example, if a consumer had an annual electricity bill of \$1000 (i.e., if  $X = 1000$ ), then with  $B/X = 0.4\%$ , the consumer would benefit by \$4 from the switch from gas to a fuel such as coal, which we assume would have a zero risk premium. This \$4 should be credited towards the bid of the coal-based bid. Since the ratio of wholesale to retail electric price ( $Ws/Rt$ ) is typically between 1/2 and 2/3, the bidder should receive a credit of \$4 on each \$600 of electricity sold (assuming  $Ws/Rt = .6$ ). This constitutes a credit of  $\$4/\$600 = 0.66\%$  of the bid price. This procedure can be expressed algebraically as:

$$X = \frac{C}{Rt} \cdot Ws, \quad \text{where } C = \text{Wholesale Expenditure.} \quad (5)$$

$$\frac{B}{C} = \frac{B/X}{Ws/Rt} = \frac{\$4/\$1000}{0.6} = 0.66\%$$

Finally, it is also important to note that there are, in principle, risk premia associated with other fuels. Although if these fuels do not have very uncertain future price trajectories and/or price changes do not have significant macroeconomic impacts, the corresponding risk premia may be extremely small. For example, coal contracts typically set fixed prices that get subsequently indexed to GNP deflators and perhaps regional wage rates (Joskow, 1985). Because these indices do not typically fluctuate much in "real" terms, the risk premium is effectively zero. Thus, in a bid evaluation scheme, a net fuel diversity value should typically accrue to projects that use non-oil and gas fuels.

Implementing an estimate of fuel diversity value from the consumer perspective in a particular bid evaluation system should take account of the elements that we have outlined. Our particular estimate should be interpreted as a sample calculation rather than the definitive treatment of this issue. Better estimates of the anticipated variability of utility- specific fuel expenses can surely be made. For example, the probability distribution of these estimates can be generated by more sophisticated means than simply consulting an economic forecasting service. Consumer surveys may generate better estimates of relative risk aversion. The link between fuel prices and macroeconomic performance is a subject of continuing interest. While all the elements considered in our analysis can be improved, our estimate does provide a benchmark of the order of magnitude that is likely to emerge from more sophisticated techniques.

Fuel choices raise other issues (e.g., national security, environmental concerns) that can potentially influence the design of a bid evaluation. These issues are usually external to the jurisdiction and/or economy that is affected by utility resource planning. Nonetheless, because issues of this kind are raised by policy-makers who must approve bidding systems, we will discuss two key externalities associated with fuel choice: the economic benefits of reduced oil consumption and incorporation of environmental impacts in bidding systems.

#### **4.4 Fuel Choice Externalities**

The standard definition of an economic externality is any aspect of a transaction whose costs or benefits do not accrue to the parties directly involved. The political system periodically adjusts the requirements imposed on transactors that may change a given effect from being external to being internal or vice versa. Such choices are also posed in the design of bidding systems. State regulatory authorities may wish to embody policy preferences in the evaluation scheme that reflect a social value which is external to the economic interests of the transactors. The effect of such a policy choice is to improve the competitive position of technologies offering the desirable attribute, and perhaps to raise the cost of power to consumers. In this section we examine two kinds of externalities associated with fuel choice: the economic benefits to the U.S. from reduced oil consumption and environmental concerns. Sample calculations show that the size of such effects can be large.

##### **4.4.1 National Benefits of Reduced Oil and Gas Consumption**

Our discussion of the value of fuel diversity addressed the willingness of various economic agents to pay for reduced fuel price risk. The risk in question was the chance that oil and gas prices would be very high. To insure against this risk, there is some willingness to pay a premium for other fuels above their expected value. Apart from these risk considerations, there are other benefits to reduced oil and gas consumption. Because oil and gas are non-renewable resources, reducing the use of these fuels can have the benefit of reducing their long-run price. This benefit is external in the sense that it flows to all consumers, and not simply to those responsible for reduced oil and gas use. In this section we provide some very rough estimates of the possible economic benefits of reduced oil consumption to the nation.

We assume that a utility that purchases power from a producer that uses an alternative fuel (e.g., coal, hydro, biomass) effectively displaces some fraction of the potential oil and gas demand of the utility sector. Currently, oil- and gas-fired generating units are the marginal resources for most U.S. utilities. Gas is the dominant fuel, although much of the fossil-fueled U.S. generating capacity has the capacity to switch fuels (EIA, 1985).

In our analysis, we initially make the assumption that oil and gas are close substitutes over the longer term, which allows us to treat the complex links between world oil and gas markets in a quite simplified fashion. Over the long-term, we assume that using coal as an alternative fuel reduces the world demand for oil. This view is not realistic as these markets are functioning today. Currently, the linkage of oil and gas markets is weak because of substantial availability of gas supplies at low costs, i.e., gas use can increase and its costs rise without being affected by oil prices. Over the longer term, the ability of freed up gas to displace imported oil depends on one's view of the gas markets. If the weak linkage continues over the long run, this implies that

the marginal cost of new gas supplies are not much higher than current embedded costs. The opposite view is that increased gas consumption will use up today's inexpensive supplies more rapidly. Moreover, the marginal cost of new gas supply is higher than current embedded costs and increasing. Under these conditions, the linkage of oil and gas markets is strong, i.e., changes in gas use can affect oil prices. Our analysis is based on the assumption of strong linkage. Therefore the estimates of the substitution benefits represent upper bounds. Should this view be incorrect, the benefits will be substantially lower.

We are particularly interested in the relationship between reduced world oil demand and the price of imported oil to the United States. Reduction in U.S. oil imports benefits the national economy by increasing domestic purchasing power and reducing the trade deficit. We assume that reductions in the price of domestic oil are in effect wealth transfers from U.S. producers to consumers, but have no significant net impact on the nation.

Equation (6) provides a rough estimate of the economic benefit of a possible short-term response to reduced oil demand, expressed in terms of national savings ( $S$ ) per kwh for a given oil demand reduction (see Appendix C for a more detailed analysis of short-run effects and derivation of this equation). The equation is given by:

$$S = \frac{m \cdot \eta_s \cdot P}{b} \quad (6)$$

where:

- $b$  = energy conversion factor (kWh/barrel of oil)
- $m$  = U.S. imports as a fraction of world oil production
- $\eta_s$  = the elasticity of world price with respect to world demand
- $P$  = price per barrel of oil (real \$/barrel).

Most of these parameters are fairly easy to estimate with the notable exception of the parameter  $\eta_s$ . We have assumed that the approximate heat rate for fossil fuel steam electric power plant generation is 10,000 Btu/kWh, which means that the parameter  $b$  is about 580 kWh/barrel. The U.S. imports about 14% of world oil production and we assume that the real price of oil is about \$15/barrel. The parameter  $\eta_s$  is the most uncertain; we have guessed that the elasticity value is 1 for our short-run analysis. It is important to note that this parameter is not the same as the commonly used elasticity of demand with respect to price. In contrast,  $\eta_s$  is the ratio of the percentage change in oil prices for a given percentage change in oil demand. Thus a very rough estimate of national savings is:

$$S = \frac{0.14 \times 1 \times 15}{580} = \$0.00357/kWh = 3.6 \text{ mills/kWh} \quad (7)$$

This value of 3.6 mills/kWh represents an upper bound estimate (because the elasticity value is high) and is not insignificant in today's current environment of low energy and avoided costs (e.g., short-term avoided costs typically range between 20-40 mills/kWh in many parts of the U.S.). If a value of this magnitude were incorporated into bid evaluation schemes, it would be large enough to influence the outcome of a power auction. The procedure would involve adding the benefits from bids that relied on non-oil and gas-fired resources. Even if the benefit were

half as large (assuming a lower value of 0.5 for  $\eta_s$ ), it could still be a factor in determining the outcome of the auction. Our analysis of short-term effects, while illustrative for showing the computational procedures, has some obvious limitations because it does not capture feedbacks between oil demand and price and because the elasticity assumptions are just guesses. Thus, we now examine the potential national benefits of reduced oil consumption over the long-term, which allows us to develop an improved estimate of the elasticity of price with respect to demand.

Over the long-term, it is important to recognize that one-time changes in demand will impact current as well as future prices of oil. DOE's Oil Modeling System provides a conceptual approach that allows us to estimate this effect, which relies on one popular view of long-run oil price formation (System Services, 1985). Over time, oil resources will be depleted. At some time in the future (T), oil will become more scarce and expensive, and ultimately the price of oil will reach that of a backstop fuel. The standard economic model of the price path over time says that the oil price should rise at the real rate of interest (Hotelling, 1931).<sup>6</sup> If we know the rate of increase in oil prices, it is then possible to work backwards from time T and the backstop price at that date to find oil prices for periods prior to the exhaustion date.

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<sup>6</sup> This is essentially a consequence of the fact that at any other rate of increase OPEC could make money by selling the oil either sooner or later.

## Long-Run Oil Price Formation

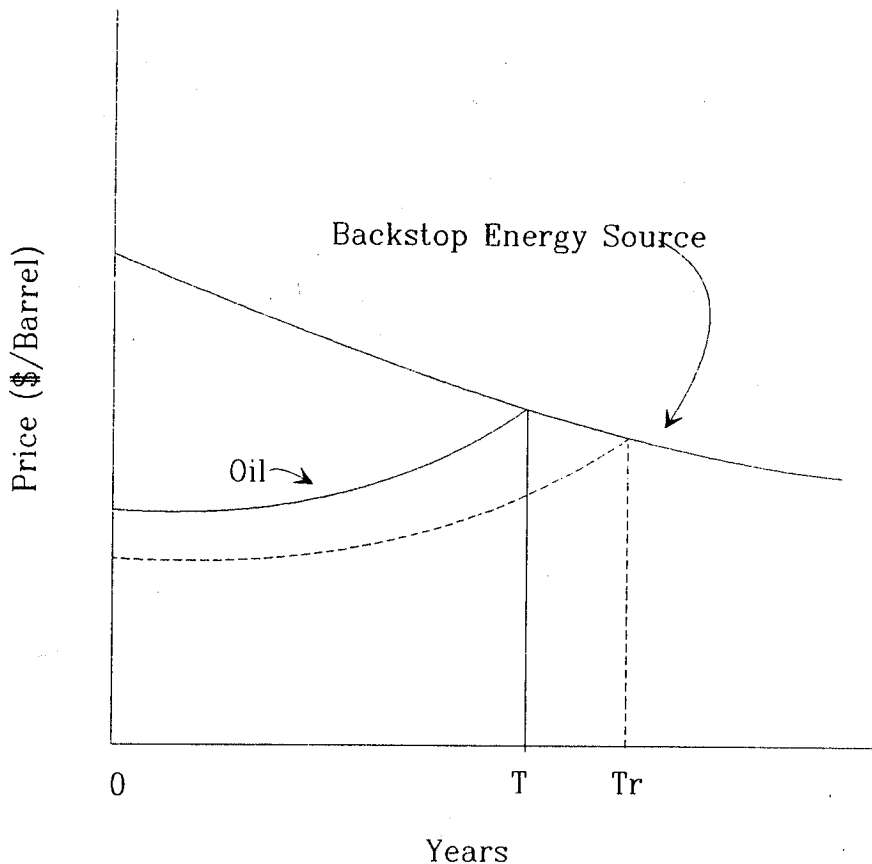


Figure 4-4. Simple model of long-run oil price formation.

Figure 4-4 illustrates this idea by showing the impact on oil prices of a change in the exhaustion date of oil,  $T$ . We have assumed that the backstop energy price decreases in real terms over time as a result of technological improvements in the cost of the backstop fuel. In addition, with reduced demand, the price of oil reaches the backstop price at a later time. Both of these effects cause oil prices to be relatively lower prior at all time periods prior to  $T$ .

Thus, our analysis of long-run impacts assumes that a decrease in present oil demand pushes the exhaustion date of oil farther into the future, which in turn causes a decrease in the real price of oil at the exhaustion date, which also results in relatively lower oil prices during previous periods. In addition, we must account for a feedback effect caused by the initial decrease in oil prices. The decrease in oil prices is likely to cause an increase in the demand for oil. However, this mitigating effect does not completely offset the initial reduction in demand.

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Effects of a one-year reduction in oil demand:  
A stylized example

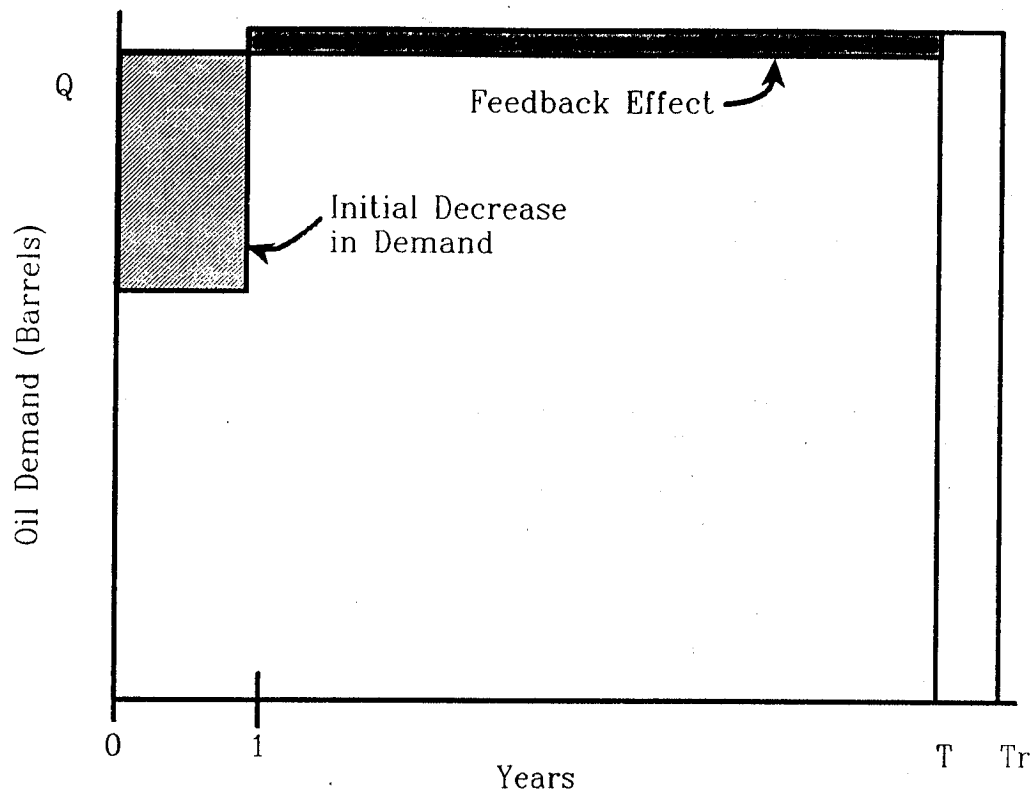


Figure 4-5. A stylized example of the effects of a one-year reduction in oil demand.

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Figure 4-5 shows the initial decrease in oil demand as a result of the choice to use an alternative fuel, the subsequent increase in demand (in response to reduced prices), and the net result, which is to move the exhaustion date into the future. Our analysis suggests that the magnitude of the subsequent increase in oil demand is less than the initial decrease (see Appendix C for details), which leads to the results given by equation (8).

$$S = \frac{m^* \cdot \eta \cdot P_o}{b} \quad (8)$$

The form of the equation is similar to our analysis of short-run effects, however note that several of the parameters need to be interpreted somewhat differently. The parameter  $m^*$  is the ratio of the cumulative total of all future U.S. imports to the current year's world oil production, which is obviously much larger than  $m$ . We develop a very rough estimate of U.S. imports for an 80-year time period. The parameter  $\eta$  is the elasticity of all future oil prices with respect to the current

year's oil demand. Practically, we can interpret this elasticity value as the impact on all future oil prices of a noticeable reduction in current demand. Not surprisingly, it is much smaller than  $\eta_s$ . The parameter,  $\eta$ , is quite difficult to estimate; our efforts to develop meaningful estimates are described in some detail in Appendix C.

Equation (9) gives the final results of our analysis of the long-run benefits to a (national) utility of reduced oil demand.

$$S = \frac{16 \times .0092 \times \$15}{580} = 0.0037/kWh = 3.7 \text{ mills/kWh} \quad (9)$$

Ironically, we found that the magnitude of the short- and long-run benefits are very similar (about 3.7 mills/kWh in real dollars), although this result is purely coincidental. This represents an average long-term value expressed in real dollars. At a minimum, we would expect that the long-term value would increase at the same rate as the increase in nominal oil prices; thus long-run effects of reduced oil demand if incorporated into bid evaluation systems, may also be large enough to affect the outcome of electric power auctions.

To summarize, we believe that our analysis of short- and long-term benefits of reduced oil demand captures real, but different, effects. The analysis of short-term benefits examines the impact of unanticipated changes in oil demand, which last only until the capital stock in the oil industry has had time to adjust. The analysis of long-run effects is based on full and optimal adjustment of the capital stock; these effects should not decrease over time. This means that the substitution of a coal-fired power plant for an oil-fired power plant will initially produce both effects. Thus, initially short- and long-run savings should be added. Long-run effects are more important because they occur over the entire lifetime of the plant, while short-run effects should last for only several years. For example, the present value of the short-run effect will be about 33% as large as the present value of the long-run effect, using a real discount rate of 4%, a 30-year plant life, and a half-life of 5 years for the short-term effect. This calculation is for illustrative purposes only and probably exaggerates the importance of the short-run effect. Our calculations of the national benefits of reduced oil consumption should be interpreted with caution; our analysis is exploratory and intended only to show that the effects under discussion may well be of a magnitude that deserve further investigation.

#### 4.5 Environmental Impacts

Many utilities (and PUCs) have responded to the increasing national concern regarding the environmental impacts of electric supply sources by explicit inclusion of environmental externalities in the bid ranking process. There are significant differences in the environmental impacts (air, water, land use) of various electric supply projects, despite the fact that all projects must satisfy state and federal environmental standards and be permitted to operate by appropriate regulatory agencies (Reeder, 1989).

For example, power plant emissions vary significantly among technologies using different fuels. Traditionally, emission levels have been governed by Federal and local policies and producers typically internalize the costs of control technology into the overall cost of electricity. Differences in pollution control costs can have significant effects on the relative competitiveness

of technologies. In addition, the relative competitive position of projects may change because the level of acceptable emissions changes over time, and thus environmental costs are not stable. As new facilities are constructed in areas subject to environmental constraint, siting authorities have increasingly relied on the "offset" concept to maintain compliance with required levels. New facilities must be substantially cleaner than existing facilities. Production from the new facility displaces production from older plants and the net emissions stay the same or decrease. The reduction in emissions from old facilities offsets the increment from new facilities.

The logic of environmental offsets is particularly important in areas, such as Los Angeles, with severe air quality problems. The South Coast Air Quality Management District (SCAQMD) oversees this process for the Los Angeles air basin. In addition to its standard setting role, SCAQMD also mandates the engineering approach that will be used to meet requirements under its Best Available Control Technology (BACT) authority. Recent estimates of the BACT costs for controlling nitrogen oxide (NOx) emissions, have been used to argue for environmental credits in resource planning (Independent Energy Producers, 1988). This argument has also been extended to California's competitive bidding context as well, because explicit resource planning underlies the bidding process. Proponents of environmental credits argue that a bidder whose project would result in a reduction of NOx emissions in the South Coast Air Basin ought to get the monetary equivalent of the BACT cost to achieve that same effect. Proponents estimate the magnitude of the credit to be approximately 1 ¢/kWh. The relative importance of environmental benefits has also been discussed and debated in New York (NYSEO, 1989; Reeder, 1989). For example, in reviewing Orange & Rockland Utilities proposed bid system, the New York Public Service Commission decided that environmental factors should be worth about 15 points (out of 100) relative to price and other non-price factors (NYPSC, 1989).

One of the major issues raised by the environmental credit approach is the question of whether or when the particular reductions in emissions will be mandated. For example, the NOx reduction credit calculated for the LA Air Basin is based on a putative calculation. It is an estimate of what it would cost to reduce NOx emissions if SCAQMD ordered this to be done. SCAQMD is considering rules that require reductions in NOx emissions, but has not issued an order. Thus, the credit is not an avoidable cost in the PURPA sense (i.e., internal to the utility system), but an external cost in the standard sense in economics.

Even if we assume that that SCAQMD was definitely going to impose NOx restrictions, we would still need to address uncertainties in pollution control equipment. In reality, BACT is a moving target because pollution control technology improves over time. Moreover, alternative strategies may offer lower or higher cost options for particular emission reduction goals. The environmental credit concept does not incorporate competitive effects in pollution control strategies and provides few incentives for lower cost methods of achieving environmental goals.

At present, there has been very little discussion of how to incorporate environmental goals into competitive bidding through means other than the environmental credits approach. As concern about these issues increases, it can be expected that this deficiency will become more apparent.

## 4.6 Project Viability

In Chapter 3, we described the significant uncertainties associated with the project development process. Winning bidders in competitive auctions may turn out not to have viable projects under the terms of their bid. The phenomenon of excessive optimism has been observed in auctions in several industries. For example, this situation has been documented in bidding for offshore oil leases, where the colorful term "winner's curse" was first formulated (Capen et al, 1971). The basic idea is that winning bidders are the most optimistic about cost or value and therefore will be more than likely to be wrong. Thus, winning bidders may not make any money or, worse, may be incapable of developing the project to initial operation. This problem has arisen in several electric power auctions, where there have been reports that selected developers were unable to finance their projects or obtain siting permits. Determining whether these occurrences are just part of a transitory learning phase and will disappear, or whether the winner's curse is persistent is a question of considerable academic and practical interest.

Existing or proposed bid evaluation systems typically address viability from two perspectives: ex ante indicators of success and damage payments. Project viability issues must be better understood if competitive bidding is to become a major or even dominant form for the construction of new power generation facilities. We can easily imagine situations in which problems in assessing project viability could become the "Achilles heel of competitive bidding." For example, bidders that are selected in an environment of widespread project failure may end up in a strong enough bargaining position to extract concessions from the buyer. This outcome would tend to make a mockery of the whole competitive bidding process.

Many utilities use "the indicator of success" approach in their bid evaluation systems. Typically, utilities develop a checklist of various project viability factors, which are often weighted equally (see Appendix F for details on particular approaches). There does not appear to be much discrimination among the factors identified. For example, some factors, such as firm financing arrangements and environmental permits, are almost impossible for bidders to obtain at the time that the initial bid is prepared. Lenders will not provide debt to a project in advance of a power purchase contract specifying prices and conditions. However, long-term contracts are precisely what the bidder is competing to obtain. Similarly, the cost of acquiring environmental permits is too great if the project does not have a purchase contract. In contrast, some project viability factors are trivial. For example, engineering design is really a minimum threshold requirement for any serious project, although merely having an engineering design can not be considered an indicator of the probable success of development.

A statistical study of project development would be a logical extension of the indicator approach. This study would involve a detailed examination of data from states in which significant private power production has been developed as a result of PURPA. A statistical model could provide evidence about the relative importance of different factors in the development process. This would ultimately lead to bid evaluation systems with project viability factors and corresponding weights that reflected the probability of success in a more realistic fashion. At the present time, this process is often performed informally by utilities and private power consultants. It is useful to speculate briefly on what a formalized analysis might reveal.

One consultant that attempts to track project development in Northern California has identified three key factors that affect project viability: (1) developer experience, (2) expansion of existing facilities, and (3) complexity of environmental permitting (Morse, Richard, and Weisenmiller, 1989). The intuition underlying the choice of these factors is clear. Private producers that have succeeded previously have an important advantage, because development is a difficult and complex process. This advantage is particularly marked in cases where the developer is simply expanding output at an existing facility, rather than proposing a project on a new, undeveloped site. In general, it is much less difficult to obtain environmental permits for expansion of existing facilities compared to obtaining permits for a new development. The complexity of permitting is also influenced by choice of technology. For example, it is typically easier to site projects with fewer emissions. In addition, there may be fewer constraints in siting projects with more remote locations, although sites near scenic or wilderness areas may incur significant environmental and permitting problems. In practice, it may be difficult to measure developer experience and permit complexity factors.

If we assume that factors such as these emerged as statistically dominant contributors to viability, there are important implications. In effect, these indicators, if embedded in bid evaluation schemes, would become barriers to entry. Basing viability measures on past development inevitably confers an "incumbent advantage." This advantage is probably realistic and appropriate as long as it is not too large. The challenge in designing bid evaluation systems is to balance the overall viability weight against other factors. The trade-off is between relying too heavily on experience factors compared to underestimating the risk and consequences of project failures.

An alternative approach favored by some utilities addresses project viability risks by establishing damage payments for projects that fail to meet development milestones. Often, the utility requires a schedule of deposits that can be used to compensate it in the case of failed development. For example, a recent stipulation on competitive bidding adopted by New Jersey mandates that winning bidders deposit a total of \$18/kW by the time they are scheduled to come on-line (New Jersey, 1988). This money is returned when the project begins operation. The deposits are timed according to an expected schedule of development that is known in advance. Failure to meet the schedule can result in a loss of up to half the deposits. Additional delays are possible, but there must be additional payment.

The approach adopted by New Jersey relies on insurance mechanisms to reduce project viability risk and is a useful supplement to the probability of success approach. If viability were a serious problem, then the linear damage schedule would not provide compensation for what would probably be non-linearly increasing costs. There is, of course, some arbitrariness in setting the level of damages and allocating them to specific stages in the development process. Simulation studies of alternative replacement power costs as a function of lead time might provide better estimates. However, this approach might actually impede development if the resulting damage requirements were too high. The price of insurance may end up costing more than the expected outcome with some failures.

The use of "bait and switch" or "holdup" tactics on the part of bidders is the ultimate trap that the utility must avoid as it attempts to ensure viable development. This phenomenon has been observed in Department of Defense procurements for new weapons systems. The winning bidder obtains the contract by offering a low price. At some point, the bidder suddenly discovers

"unavoidable" costs that could not have been anticipated and which are not the bidder's fault. The buyer must accept these additional costs or lose the whole project. In this scenario, the seller has captured the buyer. Such tactics are only possible if there is a constraint on the number of sellers (i.e., if there is no really workable competition). There is little evidence to suggest that this is the case in electric power auctions. However, there will always be ambiguous cases where sellers may make claims that they are required to obtain more revenue for reasons that are out of their control. The legal term for this is "force majeure." Such events and claims may threaten both short- and long-term viability.

## **5. METHODS FOR EVALUATING DISPATCHABILITY**

### **5.1 Overview**

Dispatchability is one of the most important operational features that private suppliers can provide to electric utilities. The utility is obliged to follow load fluctuations by varying the output of its plants. Many engineering and contractual constraints limit the operational flexibility of existing utility resources. Nuclear plants are typically designed to operate at maximum capacity. It is expensive to try to vary their output and any output variations that can be achieved are relatively small and slow. Qualifying Facilities (QF) that sell under PURPA regulations are also inflexible. The utility's obligation to purchase QF output at all times makes these resources "must run." Unless there are specific contractual provisions for curtailment of QF production during low load periods, utilities with large amounts of QF capacity and nuclear plants can experience "minimum load" problems. Minimum load problems occur when "must-run" generation exceeds load. Definitions of this condition vary and its degree of severity has been disputed in particular circumstances. Nonetheless, the existence of such a problem is a very good indicator that dispatchable resources, (i.e., those that can follow load) can be quite valuable.

In this chapter we examine how dispatchability has been defined and valued by utilities and analyze how it has been incorporated in bid evaluation systems. We focus on contrasting approaches: 1) unbundling of the component features of dispatchability as part of an "open" bid evaluation system, which has been proposed by Pacific Gas and Electric (PG&E), and 2) Virginia Power's approach, which virtually requires projects to be dispatchable and evaluates the value of dispatchability using dynamic optimization techniques that attempt to capture the non-linear dependencies of the value of each project relative to all other projects. PG&E's proposed bid evaluation system includes explicit linear values for varying degrees of operational flexibility based on the utility's analysis of the differential value of these features. PG&E's unbundling of component features of dispatchability also provides a useful conceptual framework for our discussion (see Section 5.3). It is worth noting that application of this unbundling approach as part of a linear evaluation system introduces approximations to value that may be extreme.

Virginia Power's (VP) approach is potentially more accurate, although it is less transparent to bidders (and regulators) than PG&E's "open" scoring system. We analyze VP's approach in some detail because its bid evaluation system is less transparent. In sections 5.4 and 5.5, we describe VP's auction and the optimization problem, review solution methods, and develop a simulation strategy for studying Virginia Power's auction using publicly available data.

### **5.2 Power System Operational Characteristics and Planning**

The requirement that resource output follow instantaneous variations in load is a fundamental characteristic of electric power systems. Supply balances load by definition. However, it is important for utilities to segment those components of the load matching process that can be reflected in contractual terms because it can improve the value and efficiency of transactions between private suppliers and utilities. We examine the operation of power systems in some detail in order to understand the various operational elements of the load-matching process. Focusing on the different time scales that are involved in making dispatch decisions provides a useful analytical framework. Figure 5-1 illustrates the load-matching problem for Southern

California Edison (SCE) Company and shows the operation of SCE's oil and gas units for one week in August 1984. SCE's baseload resources (e.g., coal, nuclear and QF facilities), which are also operating during this period, have been excluded in order to focus on the operation of marginal resources.

The upper line in Figure 5-1 shows the total nameplate capacity of oil and gas plants that are operating during any given hour. If an oil/gas unit is operating at any level in a given hour, its total capacity is counted for that hour regardless of what the particular output of that unit may be. The lower line, labeled load, shows the total output of these units as it fluctuates over the diurnal and weekly load cycle. Qualitatively, it is important to note that on-line capacity varies much less than load over these time periods. This occurs because the utility is unable to start and stop these units quickly. During the week, nighttime loads are only about 33-50% of day-time peak loads. Yet, very little capacity goes off-line during the night, because it will be needed for the next day. During the weekend, a downward shift occurs for both curves; the peaks are lower, and some capacity is turned off. Nonetheless, we observe a similar phenomenon; capacity must be kept running at low output to handle expected demand increases.

The value of dispatchability can be understood by examining the cost consequences of the system operational features illustrated in Fig. 5-1. During low load periods, electricity production is very inefficient because many gas- and oil-fired generating units are operating at or near their minimum levels. Heat rates at or near the minimum block size are typically 20-60% higher than at the most efficient point for these units. Thus, power purchases that serve peak loads and allow units to be shut down during the weeknights have the benefit of avoiding this inefficient production. Estimates of the marginal operating cost variations in power systems (sometimes referred to as system lambda) often do not capture these important inter-temporal dynamic effects. Moreover, the cost accounting treatment and terminology used to describe this phenomenon are not uniform. Sometimes, the off-peak minimum load operating costs are referred to as "no-load fuel" (SCE, 1986); others refer to operating flexibility under the heading of "dynamic operating benefits" (DFI, 1986).

Typically, utility operators make many operational decisions, such as unit commitment, on a weekly basis. Units that are committed will be turned on and operated at their minimum size capacity block for the entire week. Large scale optimization programs are often used to determine unit commitment. These programs take into account the minimum down times of generating units as well as operating constraints, including limits on the availability of fuels, local area voltage requirements, and the speed with which units can vary output ("ramp rate constraints").

Once the unit commitment plan has been determined, the operating decisions are generally more short-term. For example, operators will make decisions that deviate from the weekly plan in response to forced outages (i.e., the random failure of units) by bringing previously uncommitted units on-line. In addition, utility operators monitor the availability of economy energy for spot purchases and take steps to insure system security even in the absence of generator outages. This latter task involves attention to ramp rate and local transmission constraints as well as instantaneous changes in load.

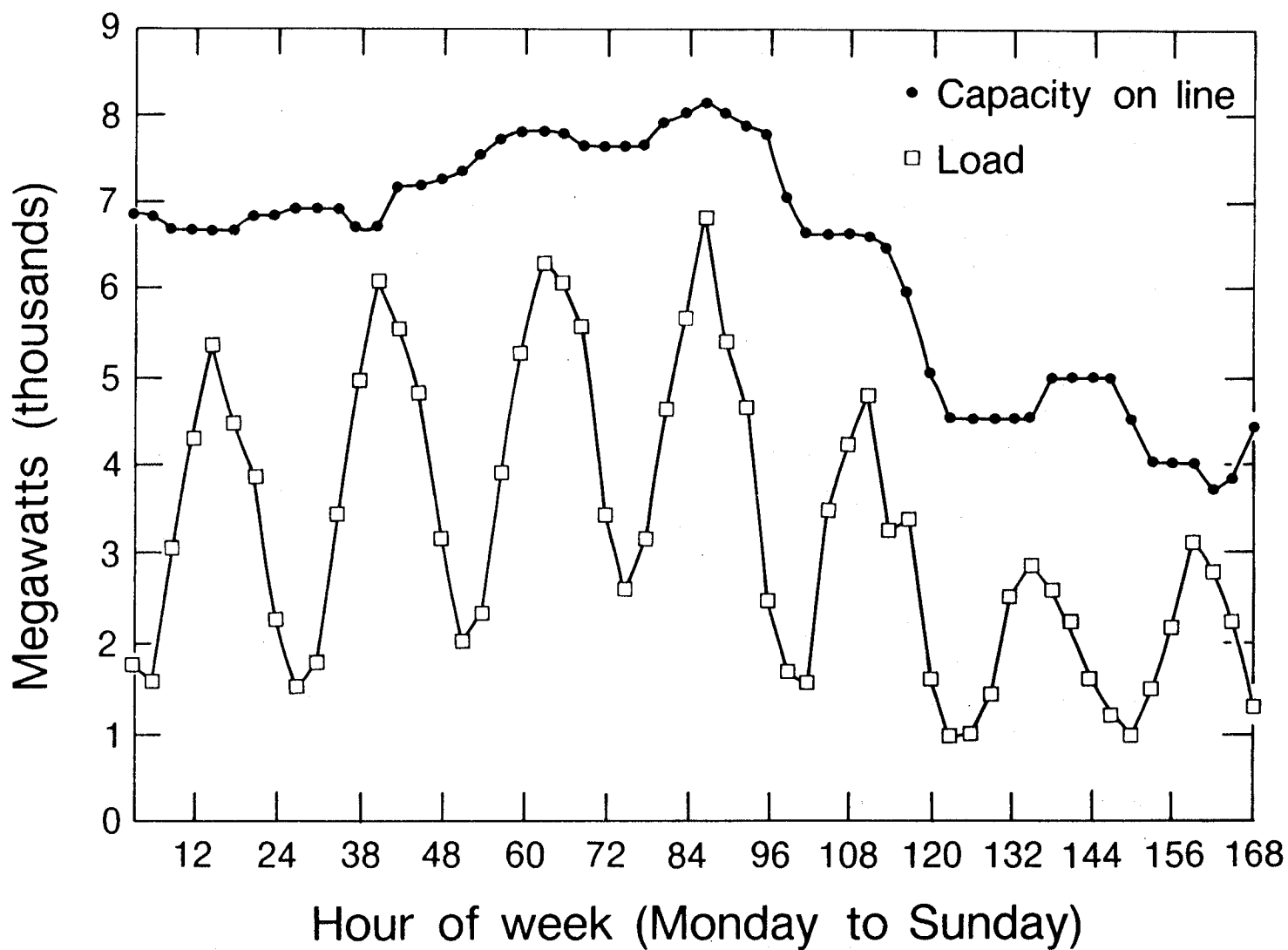


Figure 5-1 shows nameplate capacity of SCE's committed oil/gas units for one summer week in 1984 as well as the load that these units must meet. Unit commitment does not follow daily fluctuations in load.

### 5.3 Unbundling Dispatchability: PG&E's Approach

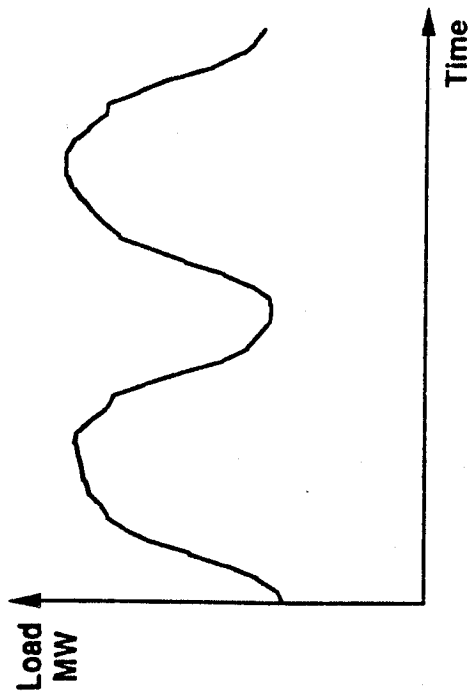
With this brief overview of power system operations and planning, we now discuss some of the important distinctions related to optimization of system performance that can be incorporated into bid evaluation systems. The most fundamental distinction involves the difference between curtailability and dispatch. Figure 5-2 provides an example of the value of curtailment (PG&E, 1988). The top curve shows the diurnal load cycle. The daily variations in marginal energy cost (system  $\lambda$ ) generally follow the same pattern. The two lower panels of the figure illustrate the relative benefits to the utility of dispatchable and non-dispatchable power. The lower left panel shows that when the bidders' energy cost (i.e., the "resource price") is greater than the marginal energy cost on the system, it would be economic to refuse the bidder's output in favor of cheaper alternatives. The curtailable resource operates only when it costs less than the utility's other marginal alternatives; benefits to the utility are shown by "plus" signs under the marginal cost curve. The lower right panel shows benefits as well as costs to the utility when the bidder has a "must run" profile and is non-dispatchable. A must-run project imposes costs on the utility during low load periods because the bidders' cost exceeds value to the utility (indicated by a "minus").

True dispatch, as opposed to curtailment, offers additional benefits which can not be observed from a marginal cost curve because it involves the intertemporal effects of reducing no-load fuel consumption. No-load fuel consumption is not strictly marginal in the sense of responding to small, instantaneous changes in load. Moreover, it occurs during both on-peak and off-peak periods, even though avoiding no-load fuel usage is due to on-peak availability. A truly dispatchable set of private suppliers would allow the utility to commit fewer units.

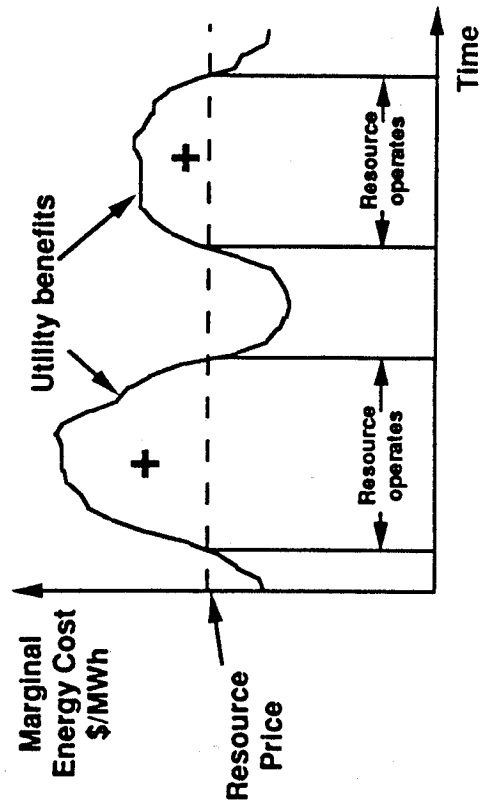
PG&E also proposes to make distinctions within the true dispatchability and curtailability classes. For curtailability, PG&E will award points to bidders based on the number of hours that the utility can reject output (e.g., 1000 hours/year, 2500 hours/year) and has suggested four curtailment levels with the maximum at 2500 hours per year. PG&E also distinguishes among dispatchability options, which allow the utility varying degrees of operational control. These include pre-scheduled dispatch, manual dispatch, and automatic generation control (AGC). AGC involves installation of equipment that adjusts the instantaneous output in response to fluctuations in the frequency of the current; this control equipment is used on utility-owned generation. Any supplier that is willing to offer AGC would automatically provide the unit commitment benefits of pre-scheduled or manual dispatch. The difference between the manual and pre-scheduled options involve how much notice the supplier gets before changing operation (less for manual dispatch) and whether spinning reserve credit accrues (only for manual dispatch).

PG&E's conceptual attempt to unbundle system operational features is quite illuminating. In practice, the implementation of such an approach, including the challenge of valuing various features, is limited by informational and analytic constraints. Production simulation models are the central tool used to evaluate dispatchability features. These models are designed to simulate power system operations over time horizons longer than the operator's one week planning horizon. Studies that use these models typically involve projections over one to twenty year periods. In addition, most production cost simulation models can only represent short-term system operating constraints in a limited fashion compared to unit commitment models. Production simulation models account for the effect of random forced outages and compute expected values

## Energy Production



### Dispatchable Resource



### Nondispatchable Resource

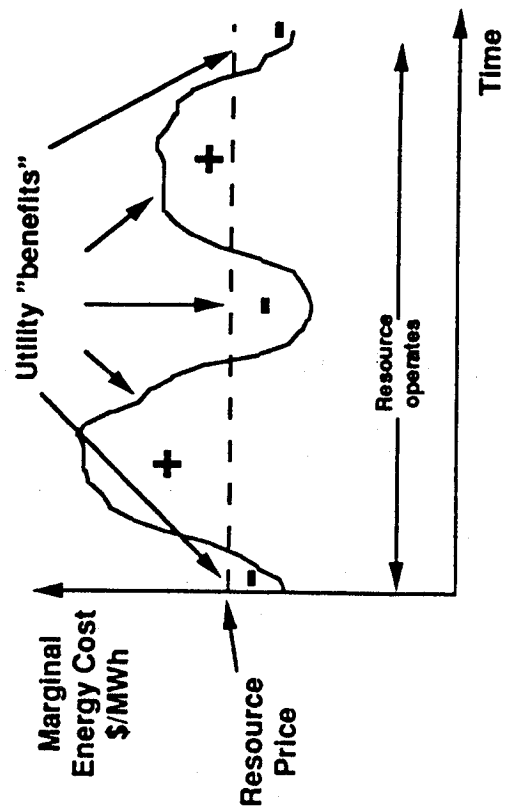


Figure 5-2 shows relative benefits to utility of resources that are dispatchable compared to resources that are "must-run" and not dispatchable. Must-run resources can have negative benefits during low cost periods. Source: Putnam, Hayes, & Bartlett, California Utilities Bidding Workshop, December 1988.

of cost and production given forecasts of unit availability. Some of these issues are treated differently in unit commitment models.

Production simulation models also vary significantly in their structure and level of detail (Kahn, 1988). Most models calculate a marginal cost curve such as that shown in Figure 5-2, although not always on an hour-by-hour basis. Benefits of curtailability options can be calculated with any model that can compute a marginal cost curve. In contrast, unit commitment savings can only be captured if the simulation model has that feature. There are substantial differences in algorithms and the degree of approximation among the models in representing unit commitment decisions. Similarly, spinning reserve benefits can only be calculated in a model that incorporates this constraint.

Thus, the detailed, complex production simulation models have the structure necessary to provide estimates of the various component elements of dispatchability; *if* the user knew how much of each feature was going to be offered by bidders and accepted. The fundamental information problem is that these quantities are only revealed through the auction process itself. Estimates of the total quantity offered of each feature are important because the value of these operational attributes is non-linear. There are diminishing returns to any given feature, and the value of one depends on the quantity of other features that are available. Proponents of "open" bid evaluation systems argue that the interactions and non-linearities only become significant when the quantities purchased are large relative to the size of the system, thus the assumption of linearity introduces only a small bias.

To some extent, defining what constitutes large and small in the context of incremental additions to an existing electric power system is an empirical question that can be answered by system simulations. Adopting the linear evaluation approach in which bidders self-score shifts the risk of making accurate value estimates onto the utility. The advantage of the open self-scoring approach is that it clarifies the bidder's problem in optimizing his offer. The cost of this transparent system is some potential inefficiency in the mix of projects accepted. It is useful to examine a stylized example in order to illustrate how a relatively inefficient mix of projects can become the winning bidders in an "open" bid evaluation system.

### 5.3.1 Inefficiency of Linear Prices for a Large-Scale Auction

Table 5-1 shows representative measures for the relative value of manual dispatch and curtailability. We believe that these values are not unreasonable, although they have not been computed for any particular utility system. The values are expressed as variable price multipliers. Thus, the variable price value for 500 MW of power with manual dispatch is 25% greater than the value of this quantity of power if it were must-take. It is important to note that the relative value goes down as the quantity of power supplied increases. Thus, for 1500 MW supplied, the average value multiplier is only 1.10 (see column 3). We show a similar value schedule for curtailment, where the decline is less pronounced. Utility A uses an "open" bid evaluation system and wants to buy 1500 MW of power. The utility announces a linear price schedule using as multipliers the values 1.25 and 1.06 for manual dispatch and curtailment (column 4). In effect, the utility is assuming that winning bidders will supply 500 MW of curtailable power and 500 MW of power that can be manually dispatched. Implicitly, it also assumes that 500 MW of power will be must-take in order for the utility to purchase 1500 MW.

**Table 5-1. The inefficiency of linear prices for a large-scale auction:  
An illustrative example.**

(1) Option	(2) Quantity	(3) Value	(4) Price	(5) Bid 1	(6) Bid 2
Value of Dispatchability					
Option #1: Manual Dispatch					
	500 MW	1.25	1.25		
	1000 MW	1.20			
	1500 MW	1.10		1500 MW	
Option #2: Curtailment					
	500 MW	1.06	1.06		
	1000 MW	1.05			
	1500 MW	1.04			1500 MW
Hypothetical Results					
Option #1: Manual Dispatch					
Cost <sup>a</sup>				1875	
Value <sup>b</sup>				1650	
Inefficiency				13.6%	
Option #2: Curtailment					
Cost					1590
Value					1560
Inefficiency					1.9%

Notes:

<sup>a</sup> Cost calculated by multiplying price times quantity bid.

<sup>b</sup> Value calculated by multiplying value times quantity bid.

We then analyze what happens if the actual results of the auction differ from the utility's implicit assumptions that are reflected in its value assignments for curtailable and manual dispatch. We calculate the inefficiencies for the two extreme cases: situations in which all winning bidders offer manual dispatch or curtailment. For simplicity, all costs and values are calculated as the product of the quantity supplied and the corresponding multiplier. A rough estimate of the inefficiency of the outcome is just the percentage excess of cost over value. The inefficiencies are large for the manual dispatch case: linear pricing results in costs that are 13.6% greater than the value of these features. The inefficiencies are much smaller for the curtailment example (about 1.9%). The illustrative results from Table 5-1 show that linear pricing is inefficient if value changes in a non-linear fashion. Non-linear values are likely when incremental capacity additions are large relative to the existing system. Our example is highly stylized and simplified; a much more detailed analysis would be required to assess the actual inefficiencies of linear pricing.

PG&E's proposed bidding system assumes that resource additions are relatively small compared to the utility's existing generating resource base. In the next section, we examine the recent auction conducted by Virginia Power and focus on the issues involved in evaluating dispatchable resources in the context of a large-scale resource procurement.

#### 5.4 Virginia Power Company's Auction

As discussed in Chapter 3, Virginia Power issued a Request for Proposals (RFP) in March 1988 soliciting bids for 1750 MW of capacity to be delivered by 1994. The magnitude of the capacity need in this RFP is its most distinguishing feature (it represents a 15% expansion of the VP system).

VP's approach provides a sharp contrast to PG&E's proposed system in which bidders have a finely developed sense of the value, or at least the price, of different kinds of dispatchability based on information provided by the utility. VP provided bidders with some general information about its expected future system configuration in its RFP: anticipated fuel costs for each of its power plants and expected levels of operation. It is unclear whether the expected levels of operation included the effect of the anticipated purchases under the RFP. Bidders then had to use this information to determine the operational profile of their project. By observing the utility's existing fuel mix, the bidder can make a rough guess about how his project might be operated. VP's approach shifts risk from the buyer to the seller because of this lack of information and because of VP's strict requirement that all projects be dispatched.

Interestingly, Virginia Power did submit an extensive filing to the Virginia Corporation Commission on May 15, 1988, which proposed avoided cost rates to be paid to small QF suppliers under the PURPA requirement (Virginia Electric and Power Company, 1988). This avoided cost filing contained more detailed information on the cost structure and expected evolution of the utility system and described VP's approach to system expansion under rate of return regulation. This information is useful, even though VP has rejected regulated investment in new generation capacity in favor of competitive procurement from private suppliers.

The avoided cost filing describes VP's method for choosing the optimal expansion plan under rate of return regulation, and how avoided costs under PURPA fit in with that approach. We are most interested in the first issue. VP's optimal capacity expansion analysis uses the EGEAS model developed by the Electric Power Research Institute (Caramanis et al, 1982a,b). Development of a capacity expansion plan involves analytical issues that are similar to those that occur in evaluation of project bids from competitive solicitations. For example, an optimization program can be used to simulate the interaction of dispatchable projects with the existing utility system. Note that if bidders were allowed to select curtailment only, computational problems become much more difficult because we would have to know when the curtailment occurred, or have to represent the limit.<sup>1</sup> On the cost side, fixed costs are specified in a similar fashion in the

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<sup>1</sup> This can be done in detailed simulation programs, but it is quite difficult in EGEAS to allow for both energy limits and dispatchability of a resource. Similarly, EGEAS cannot value unit commitment savings separately from curtailment because it does not represent the unit commitment process explicitly.

bidding RFP and the computational conventions used in EGEAS. VP allows bidders to offer leveled capacity prices, which is similar to the financial convention used in EGEAS to compute the fixed costs of generic alternatives. The results of VP's conventional capacity expansion analysis are useful because they provide some insights on the likely outcomes of the RFP evaluation.

EGEAS has three options available to the user in solving optimal expansion problems. The most accurate is based on dynamic programming techniques. In this approach each alternative is simulated in the production costing element of the program, and the total revenue requirements are computed (both fixed and variable costs). Unfortunately, computation time increases exponentially as the number of alternatives examined increases. In the conventional expansion analysis framework, the utility typically uses a small set of technology types from which it can choose as many plants as it likes. The key to computational tractability is the limit on the number of technology types. VP uses this approach in its analysis and considers only four generation options: (1) combustion turbines, (2) combined cycle, (3) fluidized bed coal, and (4) large-scale pulverized coal with scrubbers. VP's analysis showed that a total of 1400 MW of combustion turbines should be added in 1993 and 1994 and 370 MW of combined cycle facilities in 1993. VP projects that it will need an additional pulverized coal plant around 1996.

The major difference between the conventional expansion problem and large-scale bid evaluation is the number of alternatives that are considered. The response to VP's RFP produced 95 bids. Each of these projects had its own capacity, capacity price, and variable cost. It is computationally infeasible to evaluate this number of alternatives using dynamic programming. In fact, EGEAS imposes a limit of ten alternatives for dynamic programming. Therefore, we must rely on other available EGEAS solution techniques: linear programming or the Benders decomposition approach. Both options have one fundamental limitation: they ignore the integer constraints on capacity that are incorporated in dynamic programming. The integer constraint means that additional plants are chosen or they are not; there is no intermediate position. Ignoring the integer constraint means that the optimal plan will include fractional plants. While this is an annoying feature, it is not fatal. In a practical sense it is also unavoidable. The only analytic choice is whether to use linear programming or the Benders decomposition.

The Benders decomposition approach is the preferred solution technique available in EGEAS because the linear programming (LP) approach is uninteresting for dispatchable projects. The LP approach requires that the user specify a capacity factor (i.e., level of output) in advance of the optimization. This eliminates the whole dispatch simulation, and so is essentially useless for evaluating bids that only offer dispatchable power. Benders incorporates standard production simulation calculations and thus can be used to compare the fixed versus variable cost trade-off for each bid and across bids. To summarize, we conclude that EGEAS can be used to evaluate bids in a large-scale auction with features similar to Virginia Power's RFP and that the Benders decomposition approach can give useful information on the desirability of offers. However, we will need a method to deal with the fractional acceptance problem in order to interpret the results.

## 5.5 Simulating a Large-Scale Auction with Dispatchability

A large-scale competitive procurement such as that used by Virginia Power poses important analytical questions for both utilities and private producers. From the utility's perspective, what kind of modelling and decision process will yield the best choice? A simulation exercise can help address this question by examining various ways to characterize the selection process and by providing insights into the robustness of outcomes. Our answers will not be conclusive and will only address evaluation of price factors; non-price factors are not evaluated by the optimization simulation. The key question from the bidder's perspective is identifying the trade-off between capacity and energy bid prices. There is a strategic element to the bidder's choices because information on the marginal value of capacity and energy, which can be derived from the optimization, can be useful to the bidder in preparing his bid.

In this section, we describe our simulation of the Virginia Power process in which we used publicly available data to construct an EGEAS database of the VP system. We make no claim that our representation replicates the utility's actual evaluation process of the auction because the data are incomplete in many critical aspects. Despite the stylized nature of the representation, we have attempted to make the simulation as plausible as possible in order to illustrate the possible benefits and limitations of analyzing an auction that uses a "closed" process. We will make repeated reference to the public information about the actual outcome of the VP auction as a check and commentary on our results.

There are two major elements to our simulation of the Virginia Power auction: 1) representation of the Virginia Power power system prior to the procurement, and 2) representation of project bids. It is easier to gauge the accuracy of our representation of the existing power system because we can benchmark it against VP's own simulation using aggregated plant or fuel type categories. It is much more difficult to represent the bids because the offers are not public. Thus, our representation and reconstruction of the bids will necessarily be more speculative.

### 5.5.1 Modeling the Virginia Power System

The VP avoided cost filing is the most detailed source of information about the characteristics of the Virginia Power system. However, the filing is incomplete in some areas as it does not include a full description of inputs and outputs from production simulation models.<sup>2</sup> The VP avoided cost filing includes only a selection of standard inputs and some highly aggregated outputs. The bidding RFP provided more detailed outputs from a simulation as supplementary materials (e.g., unit by unit production cost simulation results), although it is impossible to determine whether both simulations used the same input assumptions.

The two areas where public data are most limited are load shapes and purchased power. We relied on a load duration curve forecast made by the Virginia Corporation Commission in developing our load shape data. This forecast was published in 1984 as part of a study of the

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<sup>2</sup> The style of complete regulatory exposure of such details is standard in California, where production simulation modelling has been investigated by both the California Energy Commission and the Public Utilities Commission. Several different models are run in regulatory proceedings, where the results are used for QF pricing, rate design, and resource planning (CPUC, 1987; CPUC, 1988).

cancellation of a proposed nuclear power plant and it is unclear if it is consistent with VP's current load forecast (VCC, 1984). We also had to make some assumptions regarding the modeling of VP's power purchase contracts with other utilities. We represented the two long-term purchases from Indiana (i.e., Rockport and Hoosier Energy Co-operative) as thermal plants that were dispatched at their variable cost. Other purchases from utilities were represented as peak shaving, while QF purchases were treated as must-run baseload energy.

We then calibrated our EGEAS simulation of the Virginia Power system to the results provided by VP in its avoided cost filing, based on a PROMOD production cost simulation. Table 5-2 shows the results for 1990. We have aggregated generation by fuel type. The generation levels of baseload resources, such as nuclear, hydro and the Mt. Storm coal plant, are quite similar. However, there is less agreement on the generation levels of VP's marginal resources. For example, the in-system coal plants, which have relatively high capacity factors, are about 7% low in EGEAS. The total of Rockport, Hoosier and Other Purchase and Interchange (P&I) shows about the same energy in both cases. However, the relatively low-cost Rockport and Hoosier purchases supply less energy in our EGEAS simulation. This result, along with the in-system coal results, suggests that our load shapes may have too little energy in the intermediate load segment and too much in the higher load segments.

**Table 5-2. EGEAS Calibration to Virginia Power's avoided cost forecast (1990).**

Plant or Fuel Category	Virginia Power forecast <sup>a</sup> (GWh)	EGEAS results (GWh)	EGEAS Deviation from PROMOD
Nuclear	19,975	19,257	-3.6%
Mt. Storm coal plant	11,101	11,057	-0.4%
In-system Coal	14,878	13,868	-6.8%
Oil/Gas	959	1,113	16.0%
Hydro	746	737	-1.2%
Pumped Storage	1,477	1,491	+1.0%
Rockport/Hoosier	5,126	3,652	-28.8%
Other Purchase & Interchange	7,334	8,750	+19.3%

Notes: <sup>a</sup> Virginia Power forecast taken from PROMOD production cost simulation.

Our EGEAS calibration is reasonably consistent with VP's reporting in the avoided cost filing of its long-term capacity needs. As part of its long term methodology, VP ran the EGEAS dynamic programming optimization to determine a hypothetical least cost expansion plan. This analysis is suggestive about the type of long-term capacity that VP might need. VP focused on four technologies: combustion turbines, combined cycle, conventional pulverized coal, and fluidized bed coal. We show VP's results along with the utility's technology cost assumptions in Table 5-3. The basic message of these results is that only oil and gas technologies are optimal to add in the period up to 1995 (e.g., combustion turbines and combined cycle).

**Table 5-3. Base case results from Virginia Power's avoided cost filing.**

Generating Unit	Number of Units	Year of Addition	Total Capacity (MW)
Chesterfield CC#7	1	1990	208
Comb Turb	15	1993	1125
Combined Cycle	2	1993	416
Comb Turb	6	1994	450
Comb Turb	3	1995	225
Coal	1	1996	740
Fluidized Bed	1	1997	200
Coal	1	1998	740
Coal	2	2000	1480
Coal	1	2001	740
Coal	1	2003	740
Coal	1	2005	740
Comb Turb	3	2007	75
Coal	2	2008	1480
Coal	1	2010	740
Coal	1	2011	740
Coal	2	2012	1480
Coal	1	2013	740
Coal	2	2014	1480
Coal	1	2015	740
Coal	2	2016	1480
Coal	1	2017	740

Type	Nominal Capacity (MW)	Cost (\$/KW)	Heat Rate (Btu/Kwh)	Forced Outage Rate (%)	Maint. (Days)	Fixed O&M (\$/kW-yr)	Var. O&M (\$/MWh)	Fixed Charge Rate (%)
Combustion								
Turbine	75	353	11600	4.3	18	0.44	4.38	13.5
Advan. Combined Cycle	208	648	7570	7.0	28	7.63	2.18	13.5
Fluidized Bed	200	1605	9750	10.0	35	31.20	3.90	12.8
Large Coal with FGD	740	1233	9850	12.0	42	26.30	6.02	12.8

We ran a similar analysis for our EGEAS database using three technologies which are representative of the types of capacity that private suppliers offered in response to the bidding RFP: combined cycle, pulverized coal, and waste coal. The technology cost characteristics were comparable to those used in VP's avoided cost filing. Our results are shown in Table 5-4. Qualitatively, the expansion plan is similar during the early years of the forecast: less capital-intensive technologies are favored over coal resources. Combined cycle units are the principal choice, in part because combustion turbines were not offered as an alternative. Only two waste coal plants are selected by 1997 (about 160 MW) compared to 3300 MW of combined cycle during the same period. Beginning in 1999, large scale pulverized coal units are chosen in our simulation, which is consistent with VP's avoided cost filing (Table 5-3).

**Table 5-4. LBL simulation of VP's expansion plan using EGEAS.**

Year	Combined Cycle (MW)	Large Coal (MW)	Waste Coal (MW)	Maximum Combined Cycle Capacity Factor (%)
1988				
1989				
1990	300			28.4
1991	600			31.3
1992			80	27.4
1993	1200			45.6
1994	300			55.6
1995	300			57.7
1996	300		80	54.1
1997	300			57.0
1998				59.5
1999	300	1050		60.6
2000		350		59.8
2001		350		56.9
2002		350		56.4
2003		350		55.2
2004		350		53.9
2005	300	350		54.0
2006		350	80	51.9
2007		700		37.0
2008		700		26.1
2009	900			31.6
2010	300	700		30.6
2011	300	350		32.4
2012	700	300	80	32.3

Notes: Our EGEAS simulation used dynamic programming techniques to solve for optimal expansion plan.

We also show the maximum capacity factor of combined cycle plants in each year, which provides some additional insights into the optimization results (see last column of Table 5-4). The capacity factor of combined cycle units is an indirect indicator of system needs. Capacity factor is defined as actual output divided by the theoretical maximum for a given unit. Because of outages and maintenance, units never obtain this theoretical maximum. Units will have a characteristic range of performance depending on which segment of the load curve they serve. Baseload units have high capacity factors while peaking units have low capacity factors and intermediate units fall in the middle. A simple static analysis tool called the screening curve is often used to define these ranges for a given load curve and technology cost characteristics.

During the first several years, new combined cycle plants operate at generally increasing levels up to a maximum of about 60%. A screening curve analysis of the three technologies shows that this is approximately the level at which coal is preferred to combined cycle. As Table 5-4 shows, the capacity factor of combined cycle units peaks in 1999, which is also the year in which coal capacity is first added in large amounts. After 1999, the general pattern is for coal capacity additions and declining maximum capacity factor for the combined cycle plants. The maximum level of operation for combined cycle units does not increase even when significant amounts of combined cycle capacity are added (e.g., 2009-2012). This suggests that these plants are being added principally to serve peaking loads and are favored only because we did not include combustion turbines as an alternative (because bidders did not offer CT projects).

We are particularly interested in the years from 1990 to 1994 because VP's solicitation requests capacity during this period. VP's system seems to prefer gas-fired technology during this period (see Tables 5-3 and 5-4). These results are somewhat at odds with the impression created by the language that VP uses in its RFP in which VP indicates a preference for coal-fired technology. This impression is conveyed largely in VP's discussion of non-price factors. Again, it is important to note that our optimization results relate only to price factors. It should not be surprising that over 60% of the capacity bid in VP's auction was either coal or waste coal because bidders respond to the incentives created by an evaluation system. Gas-fired projects accounted for less than 33% of the total capacity offered by bidders. In analyzing the VP auction, we will focus on the conflicting incentives created by VP's valuing of non-price factors and the signal given by our preliminary optimization results on system capacity needs, which are price-related.

### **5.5.2 Simulating the Bid Distribution**

Any analysis of auction processes must confront the problem of estimating the distribution of bids. Empirical studies of highway contracts (Thiel, 1988) and real estate (Brown and Brown, 1986) have relied on an approach using order statistics to generate the distribution of bids. The problem these authors have studied is simpler than ours because they are ultimately concerned with characterizing auctions in which there will only be one winner. The winner is easily determined as being either the high bidder (real estate) or low bidder (highway contracts). In our case there are likely to be multiple winners, and because of dispatchability, there is no clear way of ranking bids.

We have adopted an approach that segments the universe of bidders into technology classes, characterized by the type of fuel used. We estimate size and cost distributions for each class. The proportion of bidders in each class is fixed. Our goal is to replicate, within the informational limits, the type of bids that were actually submitted in VP's auction. Table 5-5 summarizes the public information on the bids offered. We use this classification to segment bidders (neglecting the Other category). Within each fuel type we create a distribution of capacities, capacity prices, and variable costs, which are sufficient to characterize a bid. Additional details on the procedure, parameter estimates, and the bid distribution actually used in the optimization studies are given in Appendix D.

**Table 5-5. Summary of Virginia Power's actual bids (March 1988 RFP).**

Fuel Type	Number of Bids	Total MW	Avg. Capacity (MW)
Coal	41	8212	200
Coal Waste	13	1068	82
Gas & Oil	24	4843	202
Other	17	530	31

We make the a priori assumption that bids are distributed lognormally, which is a common distribution in economics (Aitchison and Brown, 1957). We apply this assumption to variable price, capacity and fixed costs. For the distribution of variable costs, we choose a mean value that is consistent with VP's expected fuel costs. For waste coal, we use the variable costs of the Mt. Storm plant as representative of the expected value. The variances for each of the fuel cost distributions are chosen to produce a range that would capture both the highest and lowest values we might encounter. Once we have chosen a set of values for variable cost which spans the probability density and gives the a priori number of bids that we want, we must match them to capacities and fixed costs. Our procedure is designed to insure that there is no correlation between variable cost and capacity and fixed cost. This randomization is an explicit modelling choice. It is also possible to apply specific correlations at this level if desired, but we have not elected to take this approach.

We next generate a distribution of capacities, using the same procedure that was applied to the variable cost distributions. We set the mean value for each fuel type using the average value of capacity bid (see Table 5-5). However, it is difficult to create a reasonable range of capacities with these mean values and the lognormal distribution. The basic problem is that this procedure yields a few very large capacity bids (600-1100 MW) and a fair number of bids below 20 MW. We opt for excluding these extremes. To achieve this bound we chop off the tails of the distributions on capacity. The result is a range of bids that lies between 20 and 400 MW. There are other procedures that can be used, but none are elegant or well-motivated.

Finally, we capture scale economies in capital costs by applying an exponential scaling coefficient that links the capacity of a bid to its fixed costs. Thus, on average, fixed costs diminish with capacity, although there is still randomization in our procedure that assigns a fixed cost price to each capacity bid. Table 5-6 summarizes the results of these bid creation procedures and gives the number of bids for each technology and fuel type and the average values and standard deviations for capacity, fixed cost, and variable cost (see Appendix D for a complete list of bids). It should be noted that any number of bids can be created in this fashion by specifying parameters of the distribution.

**Table 5-6. LBL bid distribution: Summary statistics.**

Fuel Type	# of Bids	Capacity (MW)		Fixed Cost (\$/yr)		Variable Cost (\$/MWh)	
		Avg.	Std. Dev.	Avg.	Std. Dev.	Avg.	Std. Dev.
Coal	47	157	94	288	64	18.5	1.2
Coal Waste	15	64	38	420	102	11.5	.8
Gas	28	158	95	147	36	27.9	1.8

Figure 5-3 anticipates the results of our optimization and highlights the fact that the fixed costs of the 14 accepted bids are significantly lower than bidders' fixed costs for all bids offered for each technology type.

### 5.5.3 Optimization Studies

We use this 90 bid distribution to study the Virginia Power procurement by having EGEAS select the optimal capacity additions. We assume that the bids are all of the same form; namely, that the capacity prices are fixed (levelized) and that the variable prices escalate with fuel indices that are common to VP's plants as well. Due to computational limits within EGEAS, we must structure the competition among bidders as a single elimination tournament. EGEAS will only accept a maximum of 30 planning alternatives, so we segment our bids into three subsets. Each subset is determined by taking every third bid from the master list so that there is the same mix of technologies in each of the initial rounds. All bids that are accepted by 1994 in the first round enter the "semi-finals," because this is the year that all winners are required to be online by VP. The first round tends to reduce the 90 initial bids by about 50%, so the two semi-final competitions have 20-25 bids each. Any bid which is accepted by 1994 in this semi-final round qualifies for the final round. Bids accepted by 1994 in the final round are the tournament winners.

There are a number of computational limits in EGEAS that influence the exact specification of the procedure. We have already mentioned the fractional bid acceptance issue. It is possible that only a fraction of a bid will be accepted because the Benders decomposition does not obey the integer constraint on the capacity of bids. The remainder of the bid will often then be taken in the following year. For our purposes, we treat fractional acceptance as constituting complete acceptance.<sup>3</sup> Our results show relatively few fractions resulting from the tournament finals.

Another issue which arises is the end-of-period problem. The capacity expansion problem looks at the lifecycle costs of alternatives. We are really only interested in decisions involved in accepting bids to supply electricity through 1994. While we could let the optimization algorithm

<sup>3</sup> One could interpret an acceptance of 75% of bid capacity for a project as indicating a start date of September 1 rather than January 1. This interpretation is not completely convincing due to the perpetual representation of these fractional plants in all subsequent years of the analysis.

# Fixed costs of bids offered and accepted (Basecase)

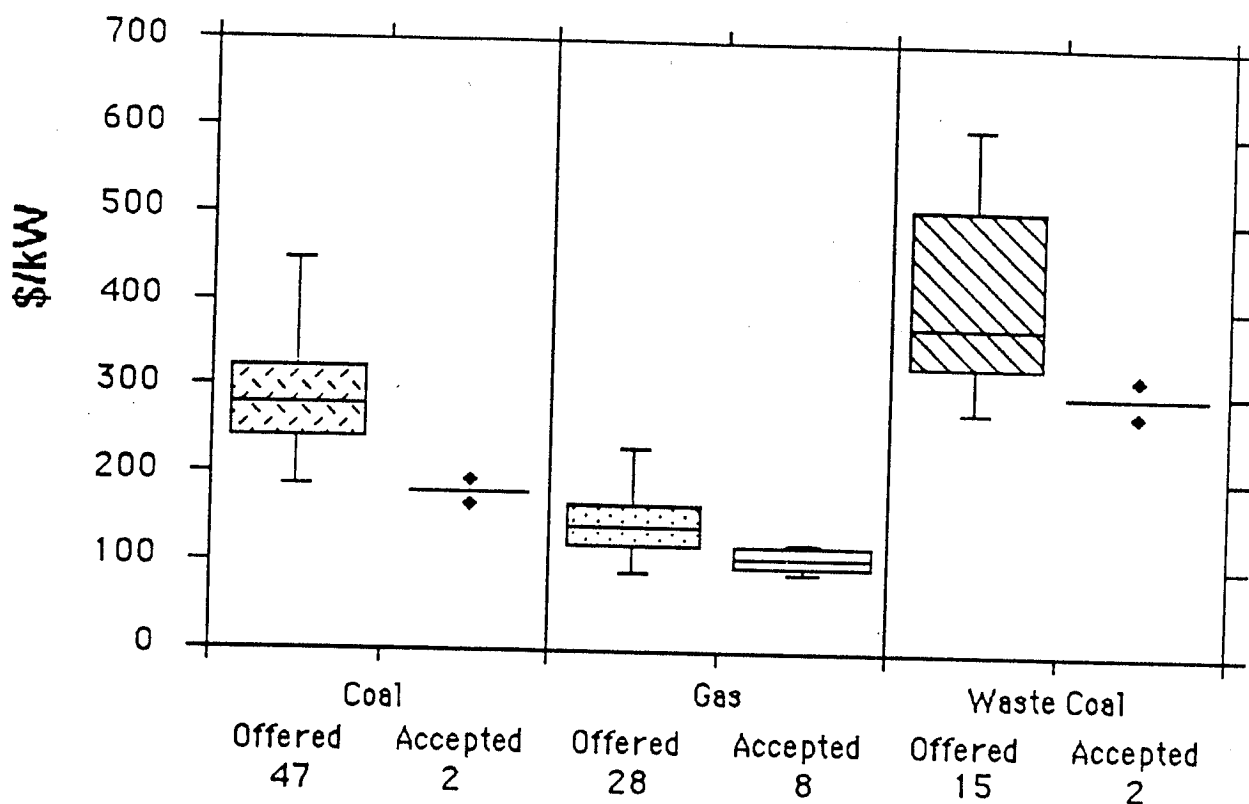


Figure 5-3 shows the distribution of fixed costs (\$/kW-year) of all of the bids that were submitted as well as winning bids for each of the three technologies in LBL's simulation of a large-scale dispatchable auction. We plot fixed cost values for the minimum, maximum, median and 25% and 75% quartile bids; accepted bids are shown as data points for coal and waste coal because only 2 bids were accepted for each technology.

continue to add capacity out beyond 2000, there is relatively little to be learned for our period of interest by such extensions. One convention that is often used is to treat the full lifecycle aspects of these problems using a simplified "extension period," which freezes the economic dispatch at a certain time, but accounts for the escalation of variable cost factors. In our tournaments we run the simulations through 1995 and begin the extension period in the following year. It is possible that results could be affected by different beginning times for the extension periods. The trade-off in this choice involves computational constraints in the optimization problem for longer simulation periods.

The basecase simulation used our 90 bid sample to select resource alternatives using the assumptions in the RFP. The results of this tournament are listed in Table 5-7 along with the actual results announced by VP in February, 1989. As expected, our simulation selected much more gas-fired capacity compared to coal-fired units. Approximately 72% of the capacity selected from our 90 bids was gas. Within the subset of gas bids, the tournament selected 8 out of 28 bids and 1737 out of 4424 MW offered. The amount of gas-fired capacity selected in the simulation was also higher than VP's actual results (932 MW out of 2084 MW, or about 45%).

**Table 5-7. LBL basecase simulation vs. VP's actual bid results.**

Fuel Type	LBL Basecase		VP's actual Bid results	
	# of Plants	MW	# of Plants	MW
Coal	2	522	4	437
Coal Waste	2	139	6	627
Gas	8	1737	6	932
Other			3	88
Total	12	2398	17	2084
			Additional Peaking	300
				2384

Notes: Data on actual results of bidding RFP are based on Virginia Power announcement of February 1989.

The discrepancy in results is not quite so extreme if we take into account the differences in the amount purchased and the reasons for those differences. VP announced a separate program to acquire 300 MW of peaking capacity to alleviate near term capacity deficiencies. Since peaking capacity can be expected to be gas turbines, it may be more appropriate to include this resource in the VP actuals. Making this adjustment brings the total capacity acquired by VP to 2384 MW compared to 2398 MW from our tournament. On this basis, the total VP acquisition of gas-fired capacity is 51% (932 + 300 MW).

The tournament results only reflect the price component of the VP auction. In Section 3.2 we indicated that VP placed 30% of the evaluation weight on non-price factors. Qualitatively,

these factors tend to favor coal. We have no way to specify how VP might embody the non-price factors in an evaluation system that is compatible with their treatment of price and the dispatchability requirement. This is a difficult problem even if we had some kind of point system to represent the non-price scores of bids. The difficulty arises because the optimization approach does not yield a rank ordering of bids. Bids are either accepted or rejected. There are a number of approaches that can be taken to the problem of integrating non-price factors with optimization. We used two different methods, both of which monetize the non-price factors in particular ways.

Our first approach focused on VP's announced preference for solid fuel projects. As Table 5-5 shows, bidders responded to this announced preference by offering twice the capacity of non-gas projects as compared to gas-fired. The RFP describes this preference in terms of "stable" prices. We can interpret this to mean that the gas price forecast contained in the RFP is somehow lower than what VP really expects gas to cost. If you think that gas costs will actually be high, then it is worth paying higher capacity costs for coal. We model this by re-running our simulation using the DRI "high" gas forecast, which is almost twice as high as VP's basecase assumptions.

Our second approach, which is not entirely distinct conceptually from the first, emphasized the indigenous economic benefits of local coal projects. Coal mining represents an important industry for the region and additional power development based on these resources would have beneficial effects on the local economy. The RFP also identified this factor separately from fuel price considerations. VP's announcement of winning bids also contained information about expected employment impacts of the selected projects. To model this factor, we assumed that all coal and coal waste bids are given a \$40/kW credit in the tournament; capacity bids were reduced by that amount to reflect the economic benefits to the local economy. The value of the credit was chosen arbitrarily, but as results discussed below indicate, it seems to be in the appropriate range. In this sensitivity case, we used VP's fuel cost assumption along with our estimated credit to reflect the preference for coal. The results of both sensitivity cases are shown in Table 5-8.

**Table 5-8. LBL simulation of VP-type auction: Sensitivity analysis.**

Fuel Type	High Gas Price (MW)	\$40/kW Coal Credit (MW)
Coal	1095	862
Coal Waste	203	264
Gas	1078	1254
Total	2376	2380

Broadly speaking, the results in Table 5-8 show that either a high gas price forecast or a substantial dollar credit to coal-fired capacity will bring the optimization results more into line with VP's actual choices with respect to the market share of gas-fired capacity. The particular values used in these tournaments are not particularly precise estimates of the implied value given

by VP to these factors. A more refined approach to eliciting the implied valuation in the VP decision would combine more moderate estimates of both factors. We have not explored this alternative, but would speculate that a case based on a combination of these two effects, each at about half the values used in our two sensitivity cases would be a reasonable approximation.

#### **5.5.4 Impact of High Gas Prices on VP System Costs: Value of Insurance**

Another way of looking at the fuel diversity benefits of choosing more coal projects is to examine the potential impacts of high gas prices on system costs given a particular supply expansion plan. We consider two supply expansion plans that could be pursued by Virginia Power: our LBL Base Case (72% gas share) and the bids accepted in our High Gas Price Scenario (45% gas share). For convenience we refer to the LBL Base case as the gas-dominated resource mix (i.e., Gas mix) and the bids accepted in the high gas price scenario as the coal-dominated resource mix (i.e., Coal mix). We then simulated the cost of these two expansion plans over the period, 1989-2005, using both the base case and high gas price forecast. Table 5-9 shows incremental and total system costs for these four scenarios. Incremental costs are defined as accepted bid prices plus all other fuel costs incurred by Virginia Power from the entire resource mix. Total cost is a rough estimate of all VP revenue requirements.

The "gas mix" case reflects VP's base case assessment of future gas prices that are most likely to occur, while one can think of the "coal mix" expansion plan, with its relatively low market share for gas, as insurance against higher than expected gas prices. The cost of this insurance is the cost difference between the "gas mix" and "coal mix" expansion cases, assuming that the base case gas price forecast actually occurs (see column 5). This is shown in both absolute and percentage terms in Table 5-9. Overall, the net present value of the incremental costs of the "coal mix" expansion plan exceeds the "gas mix" plan by \$152 million over the 17 year period. The maximum annual cost is \$158 million or about 4.1% of total revenues, which occurs in 1993. The cost of this insurance becomes negative in the year 2000, because at some point, the increase in gas prices causes the coal-dominated expansion plan to be less expensive.

The value of the insurance (i.e., choosing a coal-dominated resource mix) can be measured by comparing the cost of these two expansion plans if gas prices turn out to be high. Column 6 shows the benefits of having chosen a coal-dominated resource mix, calculated as the difference between columns 3 and 4. This is the value of insurance. In this situation, the incremental costs of the "coal mix" plan are significantly less than the incremental costs of the "gas mix" plan. In present value terms, over the 17-year period represented, the value of having chosen the coal-dominated resource mix (\$1661 million) is about 11 times greater than the cost (\$152 million). Measured as percentage changes in revenue, the incremental costs average about 0.4% higher purchasing more coal, assuming the base case gas price forecast, and about 3.8% lower in the high gas cost case.

**Table 5-9.** An estimate of the cost and value of insurance in selecting VP's future resource mix.

Year	(1) Incremental Costs (Million \$) Basecase Gas Price Forecast Gas Mix	(2) Coal Mix	(3) High Gas Price Forecast Gas Mix	(4) Coal Mix	(5) Difference for Basecase Gas Forecast	(6) for High Gas Price Forecast
1989	733	733	750	750	0	0
1990	830	844	935	952	14	-17
1991	948	948	1105	1106	1	-2
1992	1047	1085	1267	1275	38	-8
1993	1500	1657	1958	1927	158	30
1994	1850	1900	2381	2278	49	104
1995	2032	2080	2754	2611	47	144
1996	2199	2238	3148	2956	38	193
1997	2403	2436	3595	3353	32	243
1998	2604	2627	4020	3719	22	302
1999	2911	2926	5091	4679	14	413
2000	3241	3239	5979	5474	-3	506
2001	3512	3490	6636	6050	-23	587
2002	3892	3847	7622	6940	-46	683
2003	4306	4237	8647	7873	-70	775
2004	4784	4689	9785	8918	-96	868
2005	5371	5247	11229	10255	-125	975
			NPV		152	1661

Year	(1) Total Costs (Million \$) Basecase Gas Price Forecast Gas Mix	(2) Coal Mix	(3) High Gas Price Forecast Gas Mix	(4) Coal Mix	(5) % Difference for Basecase Gas Forecast	(6) for High Gas Price Forecast
1989	2949	2949	2966	2966	0.0%	0.0%
1990	3046	3060	3151	3168	0.5%	-0.5%
1991	3164	3164	3321	3322	0.0%	-0.1%
1992	3263	3301	3483	3491	1.2%	-0.2%
1993	3716	3873	4174	4143	4.1%	0.7%
1994	4066	4116	4597	4494	1.2%	2.3%
1995	4248	4296	4970	4827	1.1%	2.9%
1996	4415	4454	5364	5172	0.9%	3.6%
1997	4619	4652	5811	5569	0.7%	4.2%
1998	4820	4843	6236	5935	0.5%	4.8%
1999	5127	5142	7307	6895	0.3%	5.6%
2000	5457	5455	8195	7690	-0.0%	6.2%
2001	5728	5706	8852	8266	-0.4%	6.6%
2002	6108	6063	9838	9156	-0.8%	6.9%
2003	6522	6453	10863	10089	-1.1%	7.1%
2004	7000	6905	12001	11134	-1.4%	7.2%
2005	7587	7463	13445	12471	-1.7%	7.2%
NPV	33854	34006	43483	41822	0.4%	3.8%

Virginia Power's base case gas price forecast is somewhat lower than other contemporaneous forecasts. For example, Table 5-10 compares Virginia Power's base case gas price forecast with EIA's most recent forecast (e.g., 1989 Annual Energy Outlook); we also include the DRI high gas price forecast for reference. Using the EIA series, for example, would reduce the magnitude of column 5 in Table 5-9.

**Table 5-10. Fuel Price Forecasts.**

Year	VP Base case Gas Forecast	EIA Base Case Forecast <sup>a</sup>	DRI High gas Price forecast
1990	2.45	2.45	5.14
1991	2.62	2.59	5.74
1992	2.87	3.00	6.62
1993	3.15	3.45	7.70
1994	3.22	3.85	8.79
1995	3.57	4.35	10.16
1996	3.98	5.06	11.56
1997	4.50	5.66	12.96
1998	5.10	6.22	14.37

<sup>a</sup> EIA, "1989 Annual Energy Outlook," DOE/EIA-0383(89), see Table A-3, Natural Gas prices for Electric Utilities. Prices were expressed in \$1988/MBtu, which we converted to nominal \$ using the GNP Implicit Price Deflator from Table C-11 in the EIA report.

If we think of these gas price forecasts in probability terms, then it will help to bring the insurance value into perspective. For example, DRI attaches probabilities to its projections and estimates the likelihood of their high gas forecast at 20%. The costs of choosing the "coal mix" plan are less than 10% of its value (\$152 vs. \$1661 million, see Table 5-9). Let us call this cost an insurance premium. Comparing the premium to the expected value of the high gas case show that the coal mix plan is cost-effective. The expected value is the 20% probability times the \$1.6 billion value, or \$320 million, which is about two times higher than the insurance premium (e.g., \$152 million). Thus, when we consider reasonable estimates of the likelihood of high gas costs, it is economic to purchase insurance against that contingency.

## **5.6 Optimization Techniques for Bid Evaluation: Summary and Discussion**

In summary, it is not useful to rely too heavily on the precise details of these calculations because they depend so heavily on the simulated distribution of bids. It must be emphasized that we know very little about the actual bid distribution. Comparing our results with the actual VP decision suggests that the greatest weakness lies in our representation of the waste coal projects. Our simulation consistently takes less waste coal capacity than actually occurred. It is not too surprising that our accuracy is poor because waste coal combustion is relatively new technology that uses circulating fluidized bed boilers, which have only been in commercial operation for a brief period of time. Our distribution of bids for this technology may have over-estimated the

average fixed and variable costs. A useful improvement would be better data collection in this area.

The most interesting questions raised by these experiments are methodological. We will couch our conclusions about these optimization studies in those terms, because the methodological issues raise questions of more general interest. One set of questions raised by this simulation is whether the optimization algorithms produce stable results. Because these are large scale problems, it is difficult to develop an intuitive feel for the results. Trusting a computational "black box" to give sensible answers may itself not be a sensible strategy. Careful inspection of the final outcome of our tournaments gives some confidence about stability. For example, in our sensitivity cases, we varied the underlying economics for some bids by altering the variable costs in the high gas price case and fixed costs in the coal credit case. We found that plants that are selected change in a reasonable fashion in these alternative cases (see Table 5-11). Roughly 70% of the capacity of the winning bidders is in a core group that wins under all three scenarios. Within a fuel group, the winners tend to be bidders with larger capacity, probably because of our assumptions regarding scale economies. Some bids are losers in all three cases and are not shown in this table (see Appendix E). In addition, there are certain projects that only win in one or two cases; these marginal bidders are our competitive fringe. In only a few cases do we select an alternative that only shows up once. When that occurs it is usually possible to identify the bid as high cost compared to the core set of winners. Thus, we often end up choosing among the same subset of alternative bids.

**Table 5-11. Stability of Winners.**

	Fuel Type	Bid#	Capacity (MW)	Base Case	High Gas	Coal Credit
Core						
	Coal	5	308	X	X	X
		12	214	X	X	X
	Waste Coal	5	78	X	X	X
	Gas	4	287	X	X	X
		6	241	X	X	X
		7	222	X	X	X
		9	192	X	X	X
		14	136	X	X	X
Competitive Fringe						
	Coal	20	153		X	X
		25	126		X	
		26	121		X	X
		29	107		X	
		40	66		X	X
	Waste Coal	2	125		X	X
		7	61	X		X
	Gas	1	401	X		
		2	176			X
		11	167	X		
		20	91	X		

A related issue associated with the stability and/or interpretability of results involves the fractional acceptance problem. For example, in its simplest form this may occur when 40% of a bid is taken in one year and the remaining 60% is accepted in the next year. This is not a problem as long as both years are in the period of interest. In these cases, we just assumed that the bid was accepted, which occurred about 30% of the time in our tournaments. A more difficult situation arises when part of a bid is taken and the rest of the plant is never taken. This occurred for the Gas #2 project in the coal credit sensitivity case. EGEAS only wanted half the capacity of a 350 MW gas bid. We decided to accept that bid at half capacity. This might be interpreted as a negotiating opportunity in which the utility induces the bidder to downsize his plant.

More difficult conceptual issues arise with respect to non-price factors. We have argued that our sensitivity cases can be regarded as representations of non-price factors, in particular fuel price risk and local economic benefits. We do not claim any particular accuracy for the numerical valuations. If this general approach were to be extended to a consistent treatment of

non-price factors, then each such factor would have to be monetized essentially as an adjustment to the fixed or variable costs of bids. While such an approach is not out of the question, it would involve a considerable extension of methods now being used. The alternative to monetizing the non-price factors would be a procedure for turning the optimization results into a point system. Use of the dual multipliers, which are discussed below, is one way a rank ordering might be constructed.

The analysis thus far has been conducted largely from the viewpoint of the utility that is buying from bidders. Is there anything in this kind of approach that could help bidders? The answer is a qualified yes. Simulating a competition can help define cost and price goals that are necessary for success. It is clear from first principles that the average bid will lose unless the number of bids is small relative to the need. In considering whether to participate in an auction, the potential bidder must assess his own potential price with the distribution of prices that he thinks will be offered by others. This essentially requires a model, implicit or explicit, of the distribution of bids. Our simulation starts with such a model and then calculates, for those assumptions, how much better than the average bid a winning bid must be. For this exercise to be helpful to the bidder, he must have some confidence in the estimate of the bid distribution.

If a bidder has gotten far enough along with his competitive assessment to try fine-tuning his bid, then simulations such as these have something to offer. For example, one output of the optimization is a "dual price" for each accepted bid. The dual price represents how much the buyer (utility) would be willing to pay for an additional unit of the same bid. It is the marginal value of the bid. The dual price is expressed in EGEAS as discounted dollars for each accepted project. It is not separated into fixed and variable elements. For strategic purposes the bidder would want to know something about how to structure his offer in those terms. In our bid distributions there is substantially more variance in the fixed cost part of the bids than the variable part (see Table 5-6). The dual prices in this case can just be divided by capacity to get a measure of value per kW. If the dual multiplier is low, the bid is marginal. If it is high the bidder has leverage to raise his price offer. Raising the fixed payment component will not affect the dispatch of the project. Raising the variable component will reduce production unless the bid is base loaded (which would probably only apply to waste coal).

The dual multipliers are of only limited value to the bidder, because the bid distribution is not known with very much accuracy. The utility, on the other hand, does know that distribution and thus can use the dual multipliers to convert the optimization outcome to a cardinal ordering (i.e., "points"). The utility can also use them as a guide for negotiations with bidders: making price concessions to bidders when dual prices are high and refusing to do so when dual prices are low. However, any major price concessions may require re-running the entire tournament.

Finally, it is useful to compare the finely discriminated taxonomy of dispatchability proposed by PG&E with the optimization analysis. The use of EGEAS suppresses many of the distinctions made possible in PG&E's static mode. The production simulation component of EGEAS does not model unit commitment explicitly. It is impossible to tell at this stage how much is lost by this, or what approximations might be used to improve the analysis. Conversely, PG&E's static approach cannot address the interactions among bids and the potential inefficiency that results from neglecting them. In principle, the optimization approach is better if

a large block of capacity is being purchased. EGEAS could be improved, however, by including unit commitment in some fashion.

It is likely that dispatchability will remain a major issue in the decentralization of power systems because dispatchability is a centralizing, coordinating function. If electric power production is subject to increasingly stringent environmental regulation, the number of operational constraints impacting dispatch will increase. Contracting for private power under these conditions will be a complex challenge.

## 6. DIFFERENTIAL EFFECTS OF BID EVALUATION SYSTEMS: ILLUSTRATIVE CALCULATIONS

### 6.1 Overview

In this chapter, we illustrate the differences among four proposed bid evaluation systems by scoring the same set of eight bids in hypothetical auctions. It is not possible to perform an exercise of this kind in a completely neutral fashion because the offers that will be made in any particular situation will inevitably be local in two ways. First, bids will reflect local resource opportunities and regional opportunities for power development are not uniform. Second, bidders respond to incentives created by the given set of evaluation criteria. Therefore, bids are shaped by the rules under which they will be scored. A further practical limitation is that bids are not made public at the level of detail required to score projects. Thus, there is no readily available pool from which a sample can be drawn.

Despite these limitations, we believe that much can be learned from a comparison of utility bidding systems as they would operate in evaluating actual projects. We rely on hypothetical bids submitted in a bidding game formulated and conducted by the California investor-owned utilities at a workshop held in San Francisco in February, 1989. The purpose of the workshop was to acquaint the community of regulators and private suppliers with the multi-attribute bid evaluation system being proposed by the utilities. To simulate an auction, workshop organizers provided resource characterizations for five projects. Participants were assigned to one of ten teams (two teams per project) and each team then worked in isolation to develop a bid for its project. Some attributes of a bid were inherent to the project, although, in many cases, project attributes were determined by the team players.

We had to make some generalizations regarding the underlying resource data in order to adapt the California bidding workshop data to our purposes. Five technologies were competing in the California workshop: gas-fired co-generation, gas-fired combined cycle, biomass, geothermal and small hydro. Not all of the resources were specified to be equally economic, nor are all of them available nationally. The most localized is geothermal. California and Nevada are the only states with commercial geothermal power production. Because we cannot literally assume that projects of this kind are relevant nationally, we interpret the data as representative of capital-intensive, low-variable cost technology. In essence, the geothermal project serves as a proxy for a coal-fired project. The fixed and variable costs of the geothermal projects are quite comparable to the ranges used for these values in our Virginia Power simulations of coal technology. We also excluded the small hydro project from our simulation. The scale of this project is an order of magnitude smaller than all others (i.e., 2 MW), and its resource economics were much more favorable. This makes it uninteresting for the competition,

In the following sections, we give brief descriptions of each power project and then score each project under bid evaluation systems proposed by four utilities/states.<sup>1</sup> We identify those

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<sup>1</sup> Note that project bids are scored based on draft RFP's proposed by utilities; the scoring system of the final RFPs approved by PUCs in New York and Massachusetts differ somewhat from the utility's initial proposals.

features that made the biggest difference between winning and losing projects and assess how well the proposed bid evaluation systems worked.

## 6.2 Description of Generic Project Bids

Table 6-1(a) provides a description of key operational and economic features of the four technologies used in this hypothetical auction. Resource characteristics include site, engineering constraints, installed costs, fuel use, operating expense, and financial structure. The financial characteristics of each project (i.e., the ratio of debt to equity) are really a bidder's variable and should interact with the pricing strategy. However, to simplify the bidding game, it was assumed that the financial structure of each project was fixed and could not be altered from the initial base case specification.

**Table 6-1(a). Characteristics of generic bids: Fixed operating/economic assumptions.**

	Combined Cycle	Cogeneration	Geothermal	Biomass
Operating Characteristics				
Capacity (MW)	45	49	45	15
Availability factor (%)	95%	95%	90%	80%
Lead time (Yrs.)	3	3	2	2
Heat rate (Btu/kWh)	8,018	8,479	N/A	10,000
Economic assumptions				
Capital cost (\$/kW) <sup>a</sup>	1,047	1,388	1,500	1,027
First-year O&M cost (\$000)	1866	3881	3210	1153
Equity financing (%)	25%	20%	20%	25%
Debt repayment (yrs.)	12	12	12	12
Interest rate on debt (%)	12%	12%	12%	12%

<sup>a</sup> All values are in 1989 dollars.

Table 6-1(b) lists some of the major options that could be determined by teams and the choices made by bidders. Each project is referred to by technology type (i.e., combined cycle, biomass) and team number.

**Table 6-1(b). Characteristics of generic bids: Discretionary options.**

Option	Combined Cycle		Cogeneration		Geothermal		Biomass	
	1	2	1	2	1	2	1	2
Fixed Price (\$/kw-yr)	\$229	\$160	\$100	\$5	\$316	\$235	\$239	\$250
Escalation Method <sup>a</sup>	C	E	E	E	C	E	C	C
Variable Price (\$/MWh)	22.1	23.6/20.6	23.8	62.5	20.1	19.0	12.9	12.9
Escalation Method								
% GNP	30	10	9	100				
% Gas	70	90	91	0				
Curtaileable/ <sup>b</sup> Dispatchability	M	M	1500	1500	1500	1500	M	M
Start Date Flex <sup>c</sup>	A/D	No	D	D	No	A/D	D	D
Site Secured	Yes	Yes	Yes	Yes	No	No	No	Yes
Failure Security	0	0	\$500K	0	0	0	No	\$300K

Notes:

<sup>a</sup> Fixed Price Escalation method: C = constant over term of agreement; E = escalates at rate of inflation

<sup>b</sup> Dispatchability/Curtaileability option: M = Manual dispatch; 1500 refers to number of hours that plant can be curtailed

<sup>c</sup> Start date flexibility: A = two-year start date acceleration; D = two-year deferral in start date

The biomass project was a 15-MW facility sited at a remote rural or agricultural location with an installed cost of \$1027/kW. The project was initially structured to have 75% debt and to offer a fixed capacity price of \$239/kW-yr and a variable price of \$12.90/MWh. At these prices the return on equity (ROE) is expected to be 20%. The two bidders made no change to the proposed variable prices, but Bidder 2 decided to increase the capacity price by about 4.5% (\$250/kw-yr). Both teams made adjustments to non-price factors. For example, both teams chose to be dispatched manually and offer the possibility of being deferred at the utility's option for two years. Bidder 1 did not secure the site or offer any failure security, while Bidder 2 secured the site and offered failure security. The underlying resource economics of this project (as specified) are so favorable that it always wins under any set of rules.

The gas-fired cogeneration project is assumed to be a 49-MW facility located at an urban industrial site with an installed cost of \$1388/kW. These costs appear to be high for cogeneration projects and may include equipment to meet very rigid NOx control requirements. The project is structured to have 80% debt. The revenue from steam sales will cover O&M costs but

otherwise contribute relatively little to earnings. The initial price configuration, which would produce a 20% ROE, is a constant fixed price of \$294/kW-yr and variable price of \$24.20/MWh. Initially, the projects were not dispatchable. However, both bidders selected the 1500 hours per year curtailment option, which is the maximum interruption consistent with the obligation to sell steam to the host facility. Both bidders also chose to purchase options controlling the site and Bidder 1 offered failure security. The fundamental economics of this project are not favorable. For example, the heat rate of this project is worse than the combined cycle project and its capital costs are greater. These input assumptions appear to be anomalous because higher capital costs should result in a project with lower heat rates. One possible explanation is that the workshop organizers believe that remaining cogeneration opportunities are limited in California because of the tremendous development that has already occurred under the CPUC's standard offer contracts. The bidders chose to make price concessions in order to improve the competitive position of this project. Bidder 1 selected an escalating capacity payment starting at \$100/kW-yr and a variable payment at \$23.76/MWh. Bidder 2's approach was more radical: the bidder offered very low capacity payments (\$5/kW-year) that were to escalate with inflation in return for high variable payments (\$62.46/MWh). This is clearly a bet on oil price escalation of major proportions. Despite these price concessions and the willingness of bidders to accept lower returns on equity, the underlying economics of these projects are so poor that they always lose in the competition with other technologies.

Thus, the geothermal and combined cycle projects are the marginal competitors, largely as a result of the underlying favorable resource economics of the biomass projects and the unfavorable economics of the cogeneration projects. The cost and siting characteristics of the geothermal project strongly resemble coal technology, except for project size. The geothermal project is a 45-MW facility sited at a remote location. The installed cost is \$1500/kW and the debt structure is 80% of capital. The initial price offer, at which ROE is 20%, is a fixed price for capacity of \$304/kW-yr and a variable payment of \$20.10/MWh. These prices are about 5% higher than the average for coal plant capacity bids used in our simulation of Virginia Power's auction and about 9% higher than the mean for coal plant variable price bids. Both projects choose 1500 hours of curtailment but decided not to obtain firm control of the site. Pricing strategy is the principal difference between the two geothermal projects. Bidder 1 increased the initial fixed capacity bid by about 4%. In contrast, bidder 2 lowered the variable price by 5% and chose a lower capacity price starting at \$235/kW-yr that escalated with inflation over the life of the project. Bidder 2's strategy results in very low debt coverage in the initial years of operation, which would probably make it quite difficult to finance an actual project.

The combined cycle plant is a 45-MW facility located in an urban area. It is designed for minimal thermal application, with steam sales that are barely adequate to allow the project to meet the PURPA test for designation as a Qualifying Facility. The steam revenues are only about 20% of O&M costs and the installed cost of the project is \$1047/kW. To meet a 20% ROE target with 75% debt financing, the price offer would have to be a fixed capacity price of \$200/kW-yr and a variable price of \$23.10/MWh. The two bidders both secured the site, declined to offer project failure security, and offered manual dispatch. The pricing strategies were quite different. Bidder 1 raised the capacity bid by 15%, lowered the variable price by 4%, and chose a variable price escalator that was only weighted 70% to gas costs, as opposed to 90%

for Bidder 2. Bidder 2 chose an escalating capacity price, starting at \$160/kW-yr and offered a time-differentiated variable price (2% above the base case on-peak and 11% below off-peak).

### 6.3 Competitive Results For Four Evaluation Systems

Table 6-2 summarizes the results of evaluating the eight bids in four scoring systems. We include the system proposed by the California utilities because this was the context in which the bids were developed, rather than the approach that has been adopted by the California Public Utility Commission (see section 3.3). Appendix F provides a more detailed description of the decision rules and criteria used to score the eight projects for the other three utilities (Boston Edison, Niagara Mohawk, and Orange and Rockland). Table 6-2 lists the size of each project, its rank strictly by price criteria, and its rank when both price and non-price factors are taken into account. In addition, we have computed the mean and standard deviation of the price score as well as the combined score of all other non-price factors. These statistics allow us to develop a sense of the real weight given to the price and non-price factors in the proposed scoring systems. Our overview of utility bid scoring systems presented in Chapter 3 provided only the nominal weighting applied to the various factors. This hypothetical auction allows us to see, for a given set of bids, what the real weights turn out to be. It should be emphasized that any analysis of the real weights of a utility's scoring system is limited by the actual or hypothetical bids evaluated in that auction. Conclusions about real weights are robust only to the degree that bids are representative.

**Table 6-2. Ranking of generic bids in four utility bid evaluation systems**

Project	Size (MW)	Price Rank	ORU	BECO	NMPC	CA
Biomass #1	15	1	2	2	1	1
Biomass #2	15	2	1	1	2	2
Combined Cycle #1	45	3	3	5	4	3
Combined Cycle #2	45	4	4	3	3	6
Geothermal #2	45	5	5	4	5	4
Geothermal #1	45	6	6	7	6	5
Cogeneration #2	49	7	7	6	7	7
Cogeneration #1	49	8	8	8	8	8
Price Score						
Mean			10.8	16.5	140.3	
Std. Deviation			6.9	10.3	87.9	
Non-Price Score						
Mean			35.1	84.9	204.9	
Std. Deviation			3.2	18.4	40.2	

Of the four systems, the ranking of projects in ORU's scoring system most closely parallels the price rank (Table 6-2). Only the order for the two biomass bids is reversed. The summary

statistics help explain this result. The absolute value of the standard deviation of the price scores for ORU is twice the standard deviation of the non-price scores. We calculate the relative variance by taking the standard deviation of price points and dividing by the standard deviation of non-price points. For ORU, this ratio is about 2.15, which means that price is considerably more distinguishing under this system than all other factors combined. Price determines the outcome of the auction because all bidders look more or less the same on non-price factors, irrespective of the fact that the absolute level of the average non-price score is three times the average price score. The relative variance is a good indicator of real weight. The Biomass #2 project is able to overcome a small price disadvantage (2 points less than Biomass #1) by offering site control (3 points) and security deposits (2 points), which are not offered by Biomass 1 (see Appendix F).

It is important to note that rank ordering of bids is not identical to acceptance or rejection. In order to designate winning projects, we must specify a cut-off quantity and a rule to deal with "lumpiness." The cut-off quantity typically exceeds the resource capacity need by some fraction (e.g., 10%) in order to account for the uncertainties inherent in scoring systems, while decision rules are required for "lumpiness" in order to address possible incongruities between the total capacity represented by winning projects and the cut-off quantity (see Rothkopf et al., 1987 for a detailed discussion of lumpiness). ORU specified a need for 100 MW in its RFP. The top three bids total 75 MW; with the fourth bid added, the sum is 120 MW. It is not unusual for utilities to accept some amount of capacity over the specified quantity, thus the first four bids would probably be winners. The stated need was 160 MW in the workshop sponsored by the California utilities, from which these bids originated. The first five bids would be winners using a cut-off quantity of 160 MW.

Boston Edison's proposed system shows much greater differentiation by non-price factors. This can be seen by comparing the standard deviations of points awarded for all non-price and price factors (18.4 points versus 10.3 points, respectively). Based on an examination of the individual non-price categories, we conclude that economic risk factors (e.g., breakeven score points for front-loading) account for much of this variance (see Appendix F). Recall, that in Chapter 4, we argued that BECo's treatment of front-loading was unduly onerous. To illustrate the impact of front-loading on the determination of winning bidders, we recomputed the mean and standard deviation of the scores if the breakeven score and additional security factors were aggregated with the price factor. In this alternative case, the mean score for price and front loading is 48.4 with a standard deviation of 26.1 points. The remaining non-price factors have a mean score of 53 and a standard deviation of only 6.9 points.

The dominant role of front loading in the BECO scoring system can also be illustrated by considering the fate of particular projects. The Combined Cycle #1 and Geothermal #1 projects are most affected by BECo's evaluation of front-loading. Both of these projects require front-loaded bids and take many years to repay the implicit loan; thus their breakeven score is quite low. Neither project makes an additional security deposit, thus they receive only 20 and 17 points respectively (Table 6-3). The parallel projects, Combined Cycle #2 and Geothermal #2, are not front-loaded and thus receive 30 points for breakeven score and 20 points automatically in the security category for a total of 50 points. This scoring difference explains the relative outcomes.

Table 6-3. Project bid scores in Boston Edison's bid evaluation system

	Maximum Score	Combined Cycle #1	Combined Cycle #2	Gas- Fired Cogen #1	Gas- Fired Cogen #2	Geothermal #1	Geothermal #2	Biomass #1	Biomass #2
Price Factor	100	17	15	0	7	14	15	33	31
Economic Confidence Factors									
Breakeven Period	30	20	30	8	15	17	30	30	27
Front Load Security	20	0	20	0	0	0	20	20	20
Project Development Confidence Factors									
Tech./Environ. Feasibility	10	10	10	10	10	10	10	9	9
Project team experience	6	6	6	6	6	6	6	2	2
Level of Development									
Siting	10	10	10	10	10	0	0	0	10
Design & Engineering	4	2	2	2	2	2	2	2	2
Permit & Licensing	6	3	3	3	3	3	3	3	3
Financing	6	4	4	4	4	4	4	4	4
Thermal Energy	2	0	0	0	0	2	2	2	2
Construct./Oper.	2	0	0	0	0	0	0	0	0
Additional Contract Deposit	4	0	0	4	0	0	0	0	4
Operational Longevity Confidence Factor									
Debt & Operating Coverages	6	0	0	4	4	0	0	1	1
Fuel Supply	6	0	0	0	0	0	0	0	0
Maintenance: O&M Contract	2	0	0	0	0	0	0	0	0
Optional Operating Security	6	0	0	0	0	0	0	0	0
System Optimization Factor									
Dispatchability/Interruptibility	10	10	10	8	8	8	8	10	10
Fuel type	10	0	0	0	0	4	4	8	8
Size	2	0	0	0	0	0	0	2	2
Location	4	4	4	4	4	0	0	4	4
Maintenance Scheduled by BECo	4	4	4	4	4	4	4	4	4
PRICE FACTORS	100	17	15	0	7	14	15	33	31
NON-PRICE FACTORS	150	73	103	67	70	60	93	101	112
TOTAL	250	90	118	67	77	74	108	134	143
	Mean	Std.	Dev						
PRICE FACTORS	16.5		10.3						
NON-PRICE FACTORS	84.9		18.4						

Careful examination of the Combined Cycle #2 and Geothermal #2 projects revealed another problem that is masked by the BECO system. Even though neither of these bids is front-loaded, the debt coverage ratios of each project are so low during the initial years of operation that it is highly unlikely that they could obtain financing. In fact, Geothermal #2 can not cover its debt payments until its fourth year of operation under the price structure that was bid. The debt coverage indicators built into the various evaluation systems tend to examine average ability to make loan payments, and not the worst case, which is the minimum debt coverage. Moreover, the occurrence of low debt coverage ratios is a more serious problem at the beginning of the contract term compared to the later years. Projects with declining debt coverage in later years are in a better position to re-finance. These projects have already amortized much of their debt and can expect to sell power, albeit perhaps at spot market rates after the contract term expires. However, projects that have low coverage ratios at the outset may never obtain financing. This raises questions about both the internal consistency of the bids in our hypothetical auction as well as the usefulness of the evaluation systems.

BECO's RFP solicited 200 MW of additional capacity by 1994 which means that it would accept the first six projects. This would include the Cogeneration #2 project, which is rejected in every other case, and exclude Geothermal #1. The lack of site control defeats Geothermal #1 in the competition between these two projects.

For Niagara Mohawk (NMPC), the summary statistics on the standard deviation of points awarded for price and non-price factors for the eight projects look qualitatively more like ORU than BECo. However, this scoring outcome results not from price determination alone (as in the case of ORU), but from relative trade-offs between front-loading penalties vs. operational, siting and environmental benefits. For example, the combined cycle plants receive significant benefits in the NMPC scoring system because of their willingness to be dispatchable (see Table 6-4). These projects receive 39 points for unit commitment, economic dispatch, and quick-start capability compared to 14 points for the geothermal projects. The geothermal projects also lose 10 points for lack of site control. Other advantages for the combined cycle plants include their fuel flexibility (6 points) and lesser environmental impact (26 points). Thus, the front-loading penalties imposed on the Combined Cycle #1 and Geothermal #1 projects (45-52 points) by NMPC's bid evaluation system are not critical for the outcome because of their advantage in other non-price factors.

It is also important to point out that for several projects we had to suppress the threshold requirements for debt coverage which were established by NMPC and BECo. NMPC requires an average debt coverage ratio of 1.5 over the life of the contract. Taken literally, this would have excluded both combined cycle and geothermal projects; thus, there would not be much of a competition. BECo requires an average debt coverage ratio of 1.25, which would have excluded both geothermal projects. We concluded that it was unreasonable to expect the project bids to replicate more stringent threshold requirements of other utilities because the ground rules in the California workshop specified only a 1.0 minimum debt coverage ratio (and no average requirement). We must simply accept this inconsistency as one of the imperfections in the experiment.

We also ranked our eight projects using the bid evaluation system proposed by the California utilities. This system differs from the second-price mechanism adopted by the California PUC because it differentiates many more attributes (see section 3 in Chapter 3). However, the

Table 6-4. Project bid scores in Niagara Mohawk's bid evaluation system.

	Maximum Score	Combined Cycle #1	Combined Cycle #2	Gas Fired Cogen #1	Gas Fired Cogen #2	Geothermal #1	Geothermal #2	Biomass #1	Biomass #2
Price Factor	850	144.5	127.5	0	59.5	119	127.5	280.5	263.5
Economic Risk Factor									
Breakeven Period	50	30	50	0	20	23.3	50	50	46.7
Front Load Security	25	0	25	0	0	0	25	25	25
Success Factor									
Tech./Environ. Feasibility									
Site Acquisition	10	10	10	10	10	0	0	0	10
Design & Engineering	10	6	6	6	6	6	6	6	6
Permit & Licensing	10	5	5	5	5	5	5	5	5
Facility Availability	10	10	10	10	10	10	10	9	9
Level of Development									
Construct./Oper.	2	0	0	0	0	0	0	0	0
Thermal Energy	2	0	0	0	0	2	2	2	2
Financing	6	4	4	4	4	4	4	4	4
Project team experience	6	6	6	6	6	6	6	2	2
Additional Contract Deposit	4	0	0	4	0	0	0	0	4
Economic Development	4	1	1	3	3	3	3	1	1
Longevity Factor									
Fuel Supply	7	7	7	7	7	7	7	3	3
Debt & Operating Coverages	6	0	1	4	4	0	0	1	1
Maintenance: O&M Contract	2	0	0	0	0	0	0	0	0
Optional Operating Security	6	0	0	0	0	0	0	0	0
Operational Factor									
Operations Optimization									
Unit Commitment	14	14	14	6	6	6	6	14	14
Economic Dispatch	20	20	20	8	8	8	8	20	20
Automatic Generation Control	10	0	0	0	0	0	0	0	0
Black Start	6	0	0	0	0	0	0	0	0
Planning Optimization									
Location	4	4	4	4	4	1	1	4	4
Unit Size	3	0	0	0	0	0	0	3	3
Fuel diversity	10	4	4	4	4	6	6	8	8
Fuel Flexibility	8	6	6	6	6	0	0	6	6
Quick Start Ability	5	5	5	0	0	0	0	0	0
Environmental Factor									
Environmental Rating	100	77	77	80	80	51	51	80	80
Environmental Benefit	10	0	0	0	0	0	0	0	0
PRICE FACTORS	850	144.5	127.5	0	59.5	119	127.5	280.5	263.5
NON-PRICE FACTORS	350	209	255	167	183	138.3	190	243	253.7
TOTAL	1200	353.5	382.5	167	242.5	257.3	317.5	523.5	517.2
PRICE FACTORS	Mean	Std. Dev	Coeff of Var						
	140.25	87.92	0.63						
NON-PRICE FACTORS	204.88	40.21	0.20						

utility's proposed system is still being developed, and thus we decided that it would not be meaningful to compute means and standard deviations of price and non-price scores. They would not be comparable to the other systems. We have reproduced the ordinal ranking of bids. In looking at the ranking of projects, we note the poor position of the Combined Cycle #2 project. In this case, the chief differentiating factor was the refusal of the bidder to offer start date flexibility. This feature, which is not even considered in the other systems, is part of the explicit incorporation of uncertainty built into the proposal of the California utilities. Each bid is evaluated under three scenarios, which reflect varying load growth and fuel price projections. The California utilities have proposed to give additional benefits to those projects that offer start date flexibility. Other bidders offered this attribute, and therefore outscored the Combined Cycle #2 project.

#### 6.4 Summary

Our hypothetical auction shows the important difference between the nominal weight given to a particular factor in a bid evaluation system and its real weight. There are differences between appearance and reality. For example, the ORU system ostensibly gives 50% of the weight to price compared to over 70% for NMPC. Yet, the systems are rather similar by several measures. In both cases the final ranking of projects is quite close to the price only rank. The relative variance of price scores to non-price scores is also similar. The relative variance is a good indicator of real weight. We measure it by taking the standard deviation of price points and dividing by the standard deviation of non-price points. This ratio is about 2.15 for both ORU and NMPC compared to 0.56 for BECo. The real effect of a factor depends upon how successfully it distinguishes among projects. This cannot be known in advance of actual data on bids. When we have actual bid distributions, then it is the variability in scores that will determine the ranking.

The distinguishing feature of the BECo system is the front-loading penalties. The breakeven score and additional project security categories shift the relative variance to the non-price factors, and determine the outcome. Although NMPC also measures front loading in the same fashion as BECo, it gives only about one-third the weight to these two factors. In some cases, the weight given to dispatchability by NMPC offsets the front-loading penalties.

A more fundamental problem for both BECo and NMPC is the joint effect of minimum threshold criteria on project debt coverage and the penalties for front-loading. It is in some sense contradictory to say that projects should be well-enough capitalized so that they can cover debt easily and then penalize them for requiring high prices at the outset to service their debt. If utilities/regulators want financially viable projects, then they must recognize the constraints under which developers operate.

There is also an issue about whether debt coverage indicators are best measured as average values or through a minimally acceptable annual value. Suppose that a developer projects a good ten-year average coverage ratio that consists of very high values in the later years, but coverage ratios that are insufficient initially. Is this project viable? Does the average value convey useful information? In this case, average values are probably not useful. This illustrates the larger problem of developing well thought out positions on the trade-off between developer's requirements and ratepayer risks.

We offer a final word of caution regarding our numerical exercise. While the issues of real weights and the differences among evaluation systems are important, the eight bids offered here are only pseudo-data at best. They represent the outcome of a game, and do not involve the kind of real world experience that is necessary to obtain a better fix on the distribution of bid features. It is important to use actual bid distributions to investigate the substantive issues raised here more reliably and systematically.

## 7. CONCLUSIONS

Competitive bidding for new electric power supplies represents both a major challenge and opportunity. The opportunity is the prospect of innovation and economies that result from competition and increased reliance upon market forces. The challenge lies in managing a highly complex process. In this study we have focused mainly on the challenges associated with implementing bid evaluation systems that take account of price and non-price factors. One recurring theme is the difficulty in designing bid evaluation systems that are both workable and yet capture the complexity of developing meaningful valuations of various electric power attributes. We have discussed several non-price factors (e.g., fuel diversity, fuel choice, environmental impacts, system operational features, development risk) that require additional quantification and, in some cases, fundamental conceptual work. In addition, the benefits of flexible planning should be incorporated into bid evaluation systems (e.g., evaluation of bids under different load growth and fuel price scenarios). In the near term, we believe that a more realistic approach to the trade-off between project viability and pricing terms is the most significant improvement needed in bid evaluation systems.

In a broad sense, problems in designing bid evaluation systems reflect tensions that exist between two fundamental forces that affect the organization of electricity markets: centralization and coordination versus decentralization. Bid evaluation involves centralized utility planning of the kind embodied in the classical capacity expansion problem. The planning issues include a determination of the need for power, the optimal mix of facilities, siting and environmental considerations, and the feasibility of alternatives. However, with the advent of competitive bidding, most of these decisions must be coordinated with business entities that are not under utility control and management. Thus, a new element of decentralized decision-making is added to the planning process, which had been absent previously. Moreover, the objectives of private suppliers are not necessarily consistent with those of utilities. Therefore, contractual mechanisms must be constructed that explicitly determine mutual requirements over long periods of time. Inevitably, issues of risk, uncertainty and moral hazard arise in this context. Finally, national policy issues and priorities (e.g., environmental and national security concerns) may assume a larger role in decisions that affect the acquisition of new electric resources, which adds an additional level of complexity. Decisions about electric power facilities have important consequences for environmental and economic policy. Social concerns about these factors must somehow become a part of the evaluation process.

It is safe to say that no consensus has emerged about how to handle the various elements involved in evaluating bids for new power generation facilities. We are in a period of experimentation. However, it is important to remember the context in which competitive bidding emerged. It was largely out of frustration with traditional methods of planning and regulation that public policy has converged upon bidding. Utilities see the bidding process as a way to limit the risks of investment. Regulators are anxious to avoid experiences with rate shock. Underlying this brave new world of experiments with competition, lies a set of attitudes that emphasize limiting risk. The difficulty that these attitudes create is that there may be no way to eliminate risk for all parties and achieve the benefits of competition.

This contradiction can best be seen in the conflict between the desire to limit the exposure of ratepayers to potential overpayments to suppliers and the financial requirements of

developers. Both the BECo and NMPC systems incorporate the goal of minimizing ratepayer exposure by penalizing front-loaded bids and/or requiring security deposits. In Chapter 4 we showed that penalties for front-loaded bids in some bidding systems appeared to be unduly onerous. These penalties are even more difficult to justify, if the utility places a high priority on assuring viable projects. The cash flow constraints on project developers are often so binding that ratepayer risk minimization strategies will end up screening out resources that may be economic in the longer run. A similar contradiction emerges in the way that project viability is measured. For example, bidders are more likely to develop successfully if they invest in site acquisition and the necessary permits. These up-front costs add to costs that must be capitalized, which contributes to potential front-loading. Encouraging bidder's to economize in this area may be counter-productive in the long-run.

In exploring the various approaches to bid evaluation that have been introduced by utilities, it is also important (though difficult) to separate features that are indicative of particular system needs from those which are arbitrary. Features like dispatchability or network siting benefits are quite likely to vary from one utility to another. It can be expected that valuation methods for these types of features are more developed compared to other attributes (e.g., environmental impacts, project viability) because utilities typically address these issues in their traditional resource planning process. However, in Chapter 5, we found that the dispatchability problem becomes quite complex when the amount of power added is large relative to the existing system capacity (e.g., greater than 5-10%). In this case, the analytical tools that have been developed to solve the traditional capacity expansion problem can be adapted to bid evaluation but at a cost in both complexity and simplification. The complexity arises because optimization models are difficult to use in a way that is consistent with other bid evaluation criteria. The simplification comes because running an optimization model imposes some important limitations on our ability to accurately simulate the utility system (e.g., suppressing the representation of unit commitment).

Our analysis of Virginia Power's and PG&E's approach to dispatchability in Chapter 5 highlights another fundamental design issue in bidding systems: the trade-off between simple, self-scoring, "open" systems that are easy for bidders to understand versus complex, difficult methods that have many elements that are "closed" to observation by the bidders. "Open" self-scoring approaches will tend to be favored by utilities and regulators that want to emphasize the fairness and transparency of an evaluation system. In cases where the acquisition of power is large relative to the existing system and the value of the bids interact with each other, a case for the more complex "closed" approach can be made on the basis of economic efficiency. Scoring systems, like the one proposed by Orange and Rockland Utilities, may end up being no different than a price only approach. For example, our analysis showed that non-price factors had almost no effect on the ranking of bids under ORU's proposed scoring system (Chapter 6). Virginia Power maintains that its approach includes a significant role for non-price criteria even within a complex price/dispatchability evaluation framework.

Utilities face the challenge of balancing the competing objectives of fairness, efficiency, and risk minimization in designing their bid evaluation systems. This is still much more of an art than it is a science. Virginia Power's evaluation system is complex, difficult for bidders to understand, and imposes a severe threshold constraint on dispatchability. Yet, VP has adopted a

tolerant policy toward bidders that offer front-loaded bids. Combining a complex and essentially closed evaluation system with financial accommodations to bidders is an interesting compromise among these objectives. The approach favored by Virginia Power is not the dominant trend at the present time. Rather, "open" systems, in which bidders can self-score their projects, seem to have more appeal to utilities and regulators, although these systems may involve some potential losses in efficiency. In addition, developing more realistic measures of project viability is a key area that needs improvement in the "open" systems.

The role of social policy in competitive bidding is still largely unexplored. We have touched briefly on fuel choice decisions in this context and raised the issue of environmental policy. It seems likely that environmental issues will become increasingly important in the bid evaluation framework. There are many procedural and analytic aspects of these questions which have not been fully articulated. For example, passage of national environmental legislation that would impose new regulations on existing power plants could have a multitude of effects on both the existing power system as well as system expansion options. New constraints on dispatch will make the power system less flexible. The capital costs associated with retrofitting existing plants with required pollution controls may encourage state regulators to require that such investments compete with new supply in future power auctions. Social policy considerations can only complicate the design and implementation of bid evaluation systems.

It is in the interest of utilities, regulators, and private suppliers to develop bidding systems that are efficient, workable, and fair. In order to achieve these objectives, it will be necessary to experiment with and analyze new ideas to determine how much information and risk sharing is appropriate. This task is important because the evolution of the electric power markets will increasingly be determined by bidding procedures and contractual arrangements. The cost of failure could be a major regulatory crisis in the power sector which all parties can ill afford.

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